PAANI PROGRAM | पानी परियोजना

ENERGY OPTIONS ASSESSMENT

Cover photo: Kaligandaki Hydropower Plant

PAANI PROGRAM | पानी परियोजना

ENERGY OPTIONS ASSESSMENT

Program Title: USAID Paani Program
DAI Project Number: 1002810
Sponsoring USAID Office: USAID/Nepal
IDIQ Number: AID-OAA-I-14-00014
Task Order Number: AID-367-TO-16-00001
Contractor: DAI Global LLC
Date of Publication: 16 December 2020

Authors: Juan Pablo Carvallo, University of California, Berkeley
Isa Ferrall, University of California, Berkeley
Daniel M. Kammen, University of California, Berkeley

Table of Contents

This chapter presents the modeling approach, input data assumptions, scenarios, and results for the energy options assessment (EOA) component of the project. The EOA employs a joint capacity expansion and production cost model called SWITCH, which was specifically adapted to produce a Nepal version. SWITCH produces a set of optimal generation and transmission investment decisions for the 2025-2040 time frame, in five-year increments, while also producing dispatch decisions for these resources to demonstrate least-cost operation to meet demand at all simulated hours. All monetary costs in this chapter are in 2019 US dollars (using the $ sign) unless indicated.

This chapter is structured as follows. Section 1 presents the modeling approach its limitations. Section 2 presents statistical summaries of the main data inputs to the model, including project location, available technologies, and costs. Section 3 introduces the scenarios developed for this project, their objective, and how to interpret their results. Individual scenarios are grouped in scenario groups (SG) that jointly examine a specific policy-relevant question. Section 4 presents results by scenario group and discusses their policy implications.

1 Modeling design decisions and limitations

In this section we briefly present the SWITCH model and report modeling decisions and assumptions developed specifically for the SWITCH-Nepal model. The SWITCH model was developed in 2008 at the Renewable and Appropriate Energy Laboratory of the University of California, Berkeley, and has been continuously developed since then. There are active versions of the model for the Western U.S. Interconnection (Nelson et al., 2012; Sanchez et al., 2015), Chile (Carvallo et al., 2014), Nicaragua (Ponce de Leon et al., 2015), China (He et al., 2016), Kenya (Carvallo et al., 2017), and Uganda (Carvallo et al., 2018).

1.1 The SWITCH model

SWITCH is a mixed integer linear program that estimates the least cost investment decisions to expand a power system subject to meeting load forecast and a host of operational constraints. The model concurrently optimizes installation and operation of generation units, transmission lines, and storage while meeting a realistic set of operational and policy constraints. SWITCH employs very high spatial and temporal resolution for each region analyzed, allowing for an improved representation of variable resources like wind, solar, and storage. The SWITCH model can be run as a linear program (LP) or as a mixed integer program (MILP). In a MILP, some of the decision variables are forced to be binary or integers. These problems are generally harder to solve, but may be necessary to adequately represent decisions that cannot take continuous values.

The SWITCH model has typically been used to simulate capacity deployment decisions (in units of MW or GW) as continuous variables, allowing the model to develop any capacity level up to a certain limit given by land, technology, or other constraints. The interaction between SWITCH-Nepal and the SABER model (used for the SSP component, see Chapter 2) required that hydropower project investment decisions be treated as binary variables: either the project is not built or it is built at its predefined design capacity. Hence, in scenarios that were designed to be exchanged with SABER, hydropower installation decision variables are treated as binary and the model is run as a MILP; in all other scenarios hydropower installation capacity is treated as a continuous variable with a range from 0 to the predefined design capacity.

The main outcome of SWITCH-Nepal is a power system pathways assessment for Nepal that quantifies costs and benefits of a range of scenarios. These scenarios are characterized by different assumptions about emergent technologies (e.g. solar PV, wind, storage), demand forecast sensitivities, and policy prescriptions and targets. This analytical approach provides a range of potential investment and operational insights on generation and transmission capacity, fuel consumption and costs, dependence on hydropower, and storage, among others, which can then be integrated within a Karnali basic planning model. Portfolio-based scenario analysis has not yet been explored for Nepal, since existing planning studies develop a single pathway with little sensitivity analyses. With the dramatically improving market position of wind, solar PV, and storage, this study will provide valuable and previously unavailable information for long-term energy planning for Nepal.

Additional variables and constraints for the SWITCH model are reported in Appendix A.

1.2 New modeling developments

There are two modeling enhancements that were developed specifically for the SWITCH-Nepal model: peaking run-of-river (PROR) plants and a reference case import strategy which we will refer to as "energy banking". These are described in the following subsections.

1.2.1 PROR implementation

The original SWITCH model only represented storage and run-of-river (ROR) plants. However, a significant portion of existing and potential hydropower capacity in Nepal comes or could come from PROR plants. Adequately representing PROR plants is very important due to their dispatchability and the consequent flexibility they bring to the system for intra-day load following.

Figure 1.1.1 provides a good example of the operational difference between PROR and ROR plants based on the dry season (January) behavior. The hourly dispatch shows how PROR units are storing water during low demand hours at night, then maintain low dispatch levels during the day, and increase to inject the full stored energy during the evening peak hours. In contrast, the ROR units are non dispatchable and provide a fixed amount of energy on each hour of the day. The value of the PROR units' flexibility for the Nepal power system is assessed in section 4.10.

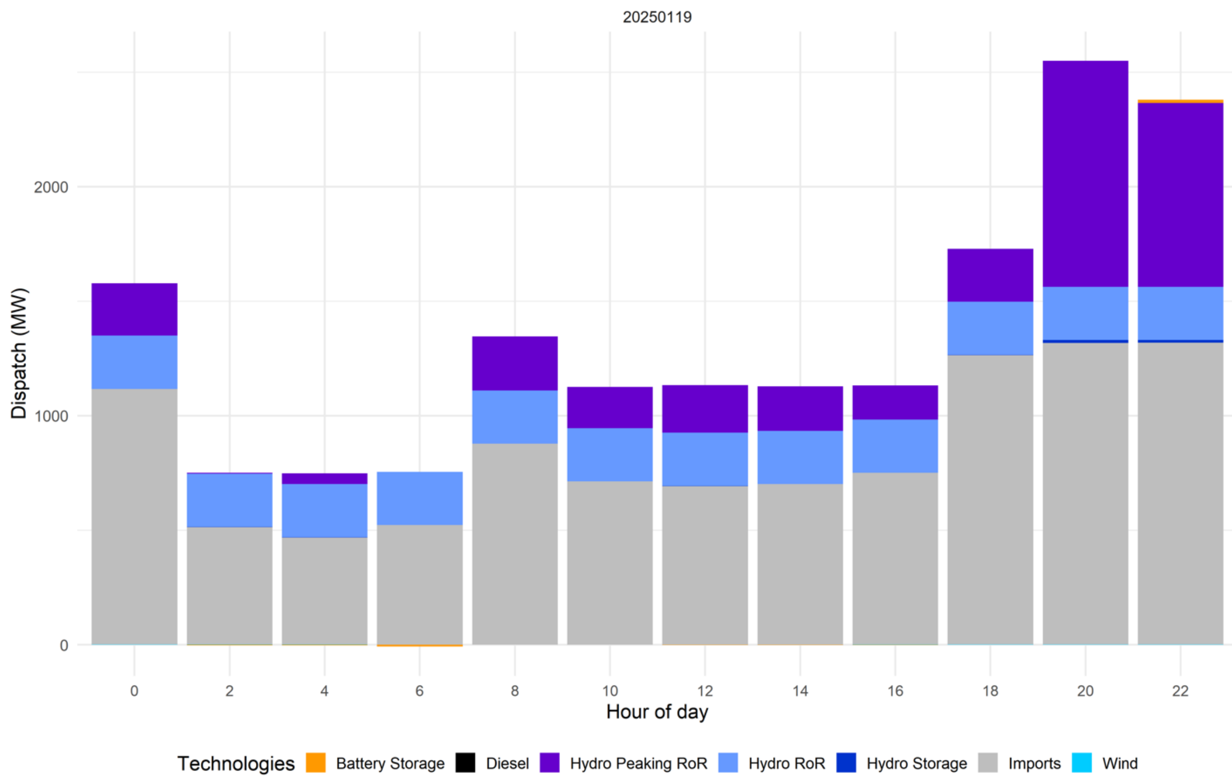

Figure 1.1.1 Hourly dispatch for a day in January 2025

The implementation of PROR in SWITCH is conceptualized by treating the plant as if it were a ROR plant paired with a battery storage unit. This approach responds to two limitations. First, the SWITCH model does not explicitly model hydrological information, just available hourly, daily, or monthly energy based on capacity factors. Second, we have no information on pondage storage capacity for PROR plants, so even if SWITCH had a hydrologic representation it would not be able to use it.

The hourly PROR production or dispatch is the sum of the instantaneously available energy – the water that is flowing directly through the penstock – and the release of stored energy from the pondage. These two energy "streams" are constrained to be less than the nominal turbine capacity on any given hour. The model includes a variable to decide how much to divert from the river flow to store in pondage and a variable that tracks the stored energy to make sure it stays under a prescribed limit. This model uses a five hour storage capacity, which means that the PROR unit can store up to 'nominal capacity' x 5 energy before being forced to stop diverting to pondage and either dispatch or spill water.

1.2.2 Import-export logic

The SWITCH-Nepal model requires a logic to define levels of imports for the next 20 years. Due to the geopolitical importance of energy imports it is very hard to exogenously define levels of imports for the model. On one hand, it could be economically reasonable to rely on imports to meet substantial portions of Nepal electric energy and capacity needs. On the other hand, it may become politically infeasible to maintain any levels of imports. While these cases are explored through sensitivities (see Section 3), the model requires a base level of imports to implement as a reference case.

Maintaining current levels of imports was deemed unreasonable for three reasons. First, imports from Nepal up to this date have not been due to economic reasons, but largely due to insufficient domestic capacity to serve load. Since the SWITCH model is designed to meet all load with high levels of reliability, the current practice does not apply to future system expansion. Second, available power for export in India may substantially change with expected high adoption of solar PV at very low cost. Hence, the current economics of imports will differ from those available in the future. Finally, there is political pressure in Nepal to reduce or eliminate imports from India to fulfill a domestic policy goal to become a net exporter.

In conversations with stakeholders, we decided that the model would implement an "energy banking" strategy as an appropriate compromise between (i) political sensitivities on cross-border power trade and (ii) lack of available data for economic decision making on imports or exports. An energy banking strategy constrains imports in the model to match exports, on an annual basis. Note that this strategy conditions imports and exports at the same time, preventing the power system from becoming a net exporter. We modify the energy banking logic in specific scenarios to examine the cost and benefits of Nepal becoming a net exporter.

The energy banking strategy imposes constraints at the physical level, not monetary level. However, the model still makes least-cost decisions where the cost of imports is relevant. We adapted results from a long-term capacity expansion model developed for India to understand the average and marginal costs that Indian power would have in the future. We used these costs to estimate a supply curve from India, such that increased import levels on a given year would result in higher prices due to more expensive PPAs needed to be signed. This is an approximate but reasonable representation of the economic costs of India power for our purposes. Details of the calibration of this supply curve are reported in Section 2.

1.3 Modeling limitations

The SWITCH model, as any power system model, has to balance complexity for computational tractability and data availability. In this subsection we highlight the main limitations of the SWITCH model that may impact the results of the Nepal case study.

First, the model employs an average hydrological year throughout the simulation horizon given the lack of access to multiple hydrological years to feed into the model. From a resource adequacy perspective, this limitation translates to higher firm capacity and available energy from hydropower projects than if the driest years were included in the simulation. The potential effects of this limitation – insufficient power system capacity to meet demand during drought years – is mitigated by employing a relatively large 15% planning reserve margin. Note that climate change may induce changes in historical hydrological patterns that could affect hydropower production in ways the model is currently not capturing.

Second, the model does not endogenously optimize the opportunity cost of water stored in reservoirs, which is exceedingly complex to solve. SWITCH has typically relied on historical operation of reservoirs to inform annual or seasonal availability for dispatch. SWITCH typically employs operational patterns from existing reservoirs to calibrate the seasonal operation of new projects based on proximity, capacity, seasonal flow profile, and other characteristics for improved project matching. However, we did not believe the single storage project active in Nepal would be a good proxy for reservoir operation in new proposed storage projects. With no information available, monthly reservoir water availability was indexed to monthly flows, which ignores the capacity of certain reservoirs to store water across several months (still allowing for intra-month storage optimization). This modeling design decision could make storage projects (particularly large projects) less valuable to the power system – since they cannot provide intra-year balancing – and potentially translate to reduced adoption of these resources in SWITCH model simulations. This limitation is mitigated by the limited number of existing and prospective storage hydropower plants in Nepal, which suggests its impact may be moderate.

Third, the model does not simulate the interdependence between hydropower projects that are located in a cascade along the same river. This is particularly important for storage projects that significantly alter river flow patterns downstream. However, since the model selects very few reservoir projects, prescribed capacity factors for run-of-river and peaking run-of-river plants are not significantly impacted by hydropower operation.

Fourth, the energy banking strategy to define imports could have unintended consequences in the expansion of the power system. For example, the model could find that certain levels of curtailment of wind, solar, and hydropower could be optimal even when considering its costs. Indeed, several models are suggesting overbuilding solar PV if its costs are low enough to meet demand in "shoulder" hours, making curtailment an optimal decision. However, curtailments are endogenously limited to be as high as imports on an annual basis based on the way the energy banking strategy is defined.

Fifth, and connected to the previous limitation, the implementation of power import and exports in the model is not primarily based on economic decisions due to lack of data availability for forecasting purchase and sale PPA prices. Several studies have explored cross-border transactions from an economic perspective (e.g. McBennett et al., 2019). However, none of these studies represented hydropower projects in Nepal with the level of detail that SWITCH-Nepal has and hence may not have captured the dynamic relationship between hydropower project selection and import levels. This topic remains open for future research.

Finally, the SWITCH model must choose the number of hours to represent the power system for each investment period. This is the result of selecting a certain number of hours per day, a certain number of days per month, and a certain number of months in the year to simulate. There is a tradeoff between choosing too many hours to better represent the idiosyncrasies of the domestic power system and making the problem intractable by including too many timepoints. The need to solve a MILP for the Nepal model puts further pressure on this tradeoff, as each MILP model instance took between three to forty eight hours to solve. The final choice was to select twelve hours in the day – essentially every other hour – and two days in the month – the peak day and a randomly selected median day. The model then selects six months in a year – every other month – to capture annual seasonality. This sampling method selects 144 hours per year for a total of 576 timepoints simulated in the model. The sampling has the obvious risk of not capturing some specific system dynamics that happen occasionally during a year. This can be mitigated by inputting the generation and transmission decisions of the SWITCH model in a production cost model for a full year of hourly simulations and further verification of the reliability of the SWITCH decisions. This step was out of the scope of the present effort, but its absence does not invalidate the results from this work.

2 Input data assumptions

This section provides quantitative information on the basic assumptions used in SWITCH-Nepal model runs. The section covers generation project investment cost, demand, transmission, and supply side resources.

2.1 Estimating hydropower project costs

Only 424 out of 1359 hydropower plants have cost data in the original version of the hydropower plant dataset. All plants with cost data were developed in the Tractebel study. SWITCH requires all plants to have a unit cost, which is usually done by using a typical technology cost per MW of installed capacity. This approach may introduce distortions in the Nepal hydropower investment decisions because of the relatively wide variation in per MW costs as reported by Tractebel, especially for the ROR plants (Figure 2.1.1).

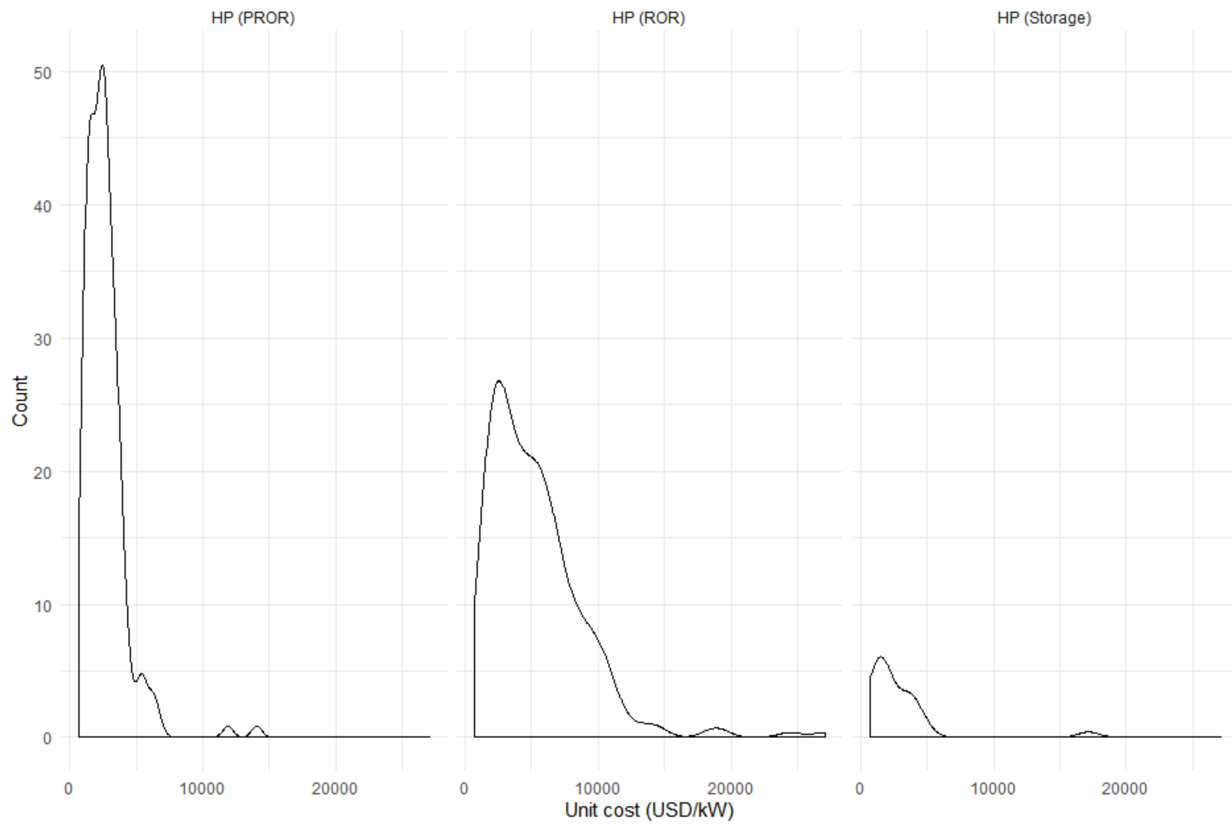

Figure 2.1.1 Distribution of hydropower unit costs by technology type

A method is required then to predict costs for hydropower plants that were not developed by Tractebel. We developed a linear regression by identifying all the fields in the dataset that have values for Tractebel and non-Tractebel hydropower units. These values are used as independent variables to fit an ordinary least square (OLS) model using the Tractebel data. We chose the total project cost in USD as the dependent variable, rather than the unit cost in USD/MW, because the installed capacity is also part of the regressors and having a derived variable as a dependent variable can introduce biases. Since the independent variables are also available for the non-Tractebel units, the model results can be used to predict costs. The functional form for the unit costs is:

*log(PROJECT_COST_USD) = a * log(LENGTH_KM) + b * log(VOLUME_TCM) + c * log(UPLAND_SKM) + d * log(DIS_AV_CMS) + e * log(BB_LEN_KM) + f * log(PCAP_MW)*

The variables are used with logarithms given their log-normal distribution (as seen in Figure 2.1.1). The regression is run separately for storage projects and for PROR/ROR projects, given their fundamentally different cost structures.

Regression results for storage projects show that installed capacity has the only statistically significant coefficient at 99% CI. The regression performs relatively well, explaining about 94% of the variation in the cost data. Regression results for the PROR/ROR projects show that the coefficients for UPLAND_SKM and installed capacity are statistically significant at 99% CI. The regression is able to explain about 87% of the cost variation in the data.

We test the predictive capacity of the regression by applying each model – storage and PROR/ROR – to the Tractebel data, and comparing the predicted and actual project cost. Figure 2.1.2 shows the results for the PROR/ROR plants and Figure 2.1.3 for the storage plants. The cost predictions for both are relatively well clustered around the unity slope, which means that there is no significant bias in the predictions. The PROR/ROR regression does show a bias towards underpredicting costs for plants with the highest costs (Figure 2.1.2, red area).

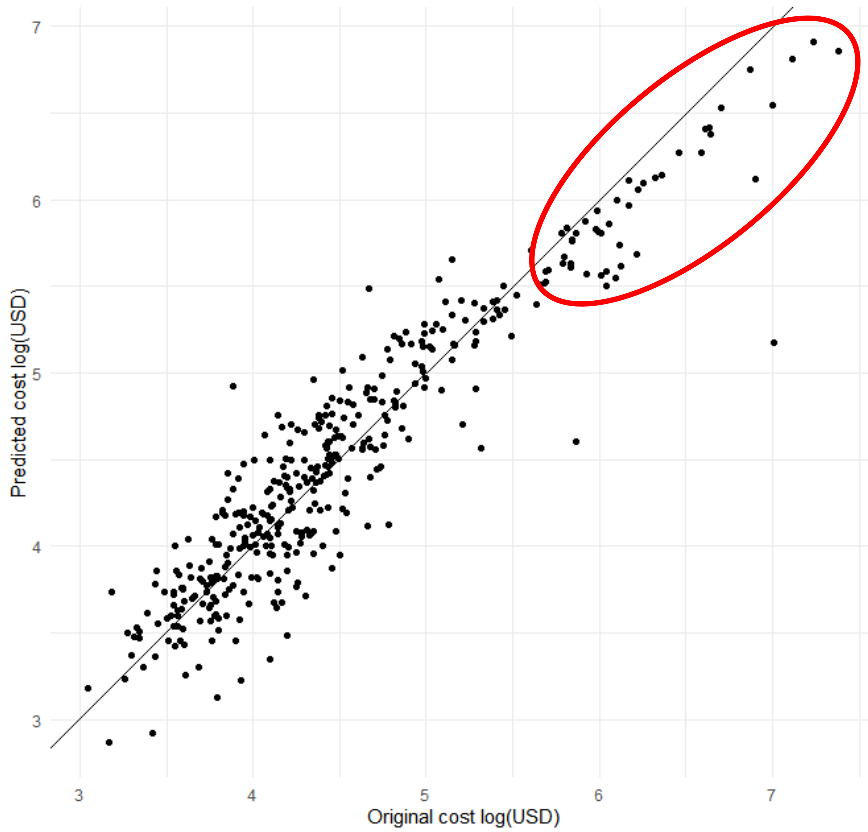

Figure 2.1.2 Predicted and original costs for PROR/ROR plants

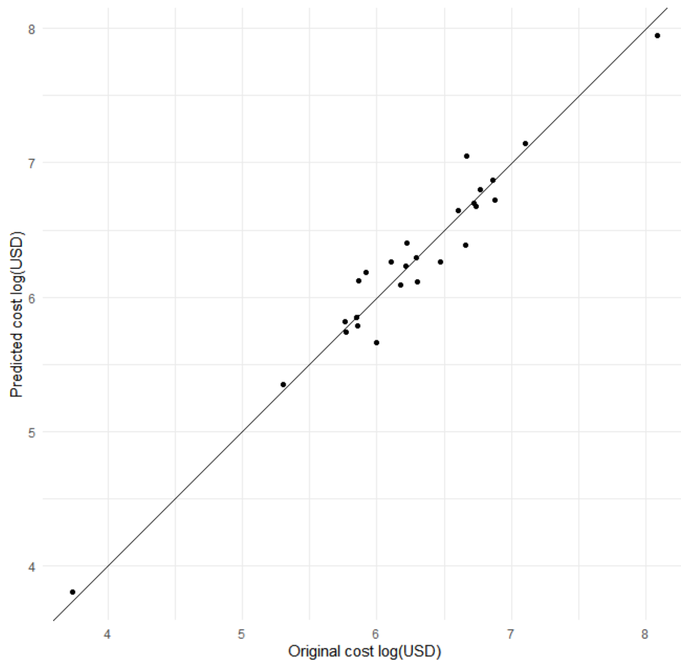

Figure 2.1.3 Predicted and original costs for storage plants

We analyze the error distribution for PROR/ROR plants by installed capacity (Figure 2.1.4). Results show that higher errors appear in plants with relatively small size. Prediction error margins are bounded around 20%, which is considered a reasonable deviation for the purposes of this study. For storage projects the prediction error is less than 5%.

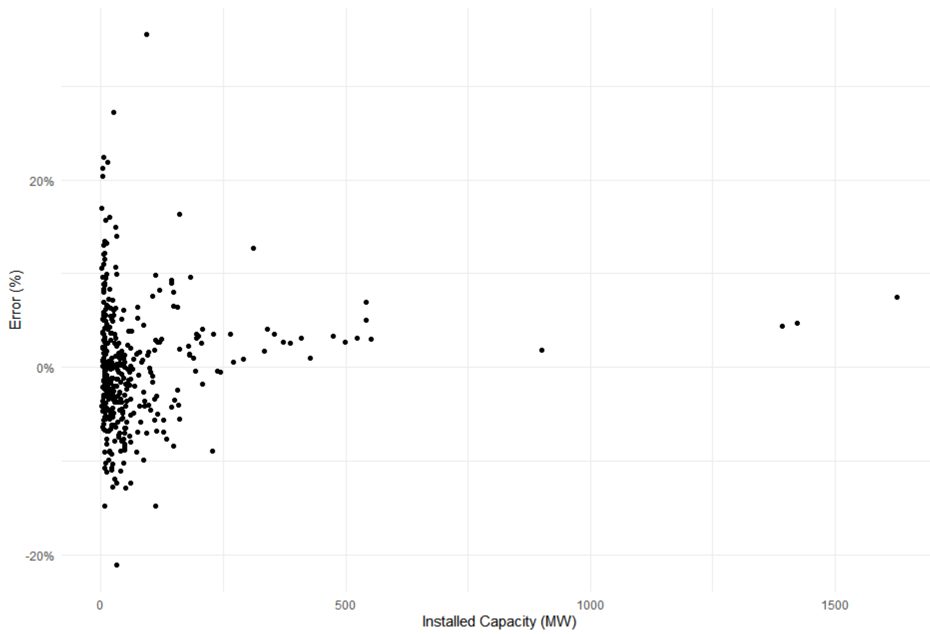

Figure 2.1.4 Error distribution by installed capacity for PROR/ROR plants

Given its efficacy, the OLS models for PROR/ROR and storage are applied to all non-Tractebel projects in the dataset to estimate their cost. However, before passing these costs as inputs to the SWITCH model, we implemented a statistical analysis to identify and remove outliers.

The statistical analysis suggested that the underpredicting bias identified during the regression analysis could bias the project costs for high cost plants. We also compared project unit costs in $/kW for different technologies with international benchmarks to identify possible outliers. This analysis resulted in using the 10th percentile as a lower bound for ROR and PROR unit costs, and the 25th percentile as lower bound for storage projects. The monetary bounds for ROR, PROR, and storage projects were 1,772 $/kW, 1,193 $/kW and 1,308 $/kW, respectively. Then, any project whose cost was under this lower bound was adjusted to the bound before being input in the model; projects with costs above the bound were not adjusted.

2.2 Demand: spatial division and load forecast

Topologically, a power system is made of hundreds or thousands of substations that are interconnected through transmission lines. Substations will typically have a generation unit or demand connected to them to inject or withdraw power from the system, respectively. Since this topological level of detail is too high for SWITCH, the power system is represented by grouping substations that are close to each other together to form “load zones”.

Load zones are the minimum unit of spatial analysis in SWITCH. There are two main criteria for load zone creation. First, load zones should roughly correspond to main consumption centers. Second, load zones should be such that transmission is relatively unconstrained within the load zone, but there may be transmission congestion in lines that connect load zones. The latter criterion allows the simulation of transmission expansion that represent the main corridors in a power system.

Load zones were created for Nepal through a spatial clustering of medium voltage (primary) distribution line and distribution transformer location, made available by the World Bank. Primary distribution system location is strongly correlated to consumption centers. A k-means spatial clustering method was employed, testing a range of clusters from 10 to 20. The tests suggested that 15 clusters was an appropriate number (see Figure 2.2.1).

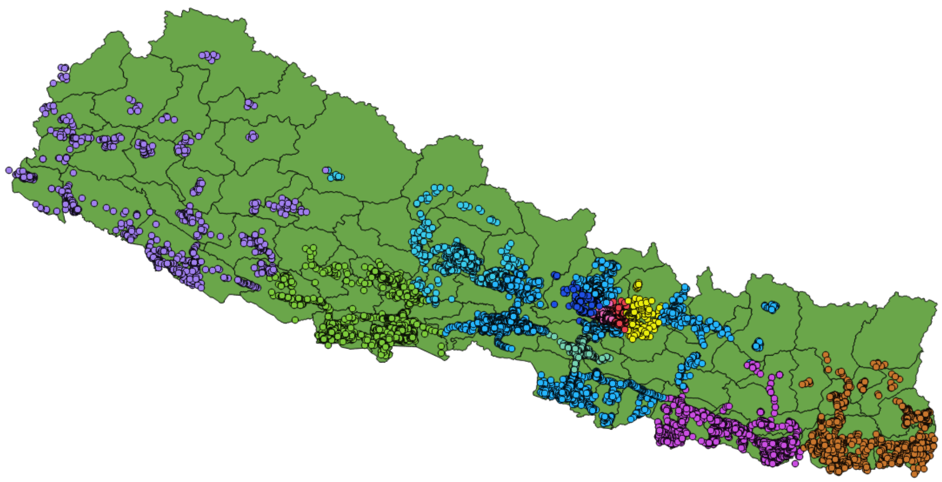

Figure 2.2.1 Distribution system network nodes with spatial clustering

Districts are the second level of administrative division in Nepal after provinces. The clusters of primary distribution voltage networks were mapped to districts by calculating the number of distribution system nodes (transformers) from a given cluster that were located on each district. The district was assigned to a cluster based on the share of nodes located in that district (see Figure 2.2.2). The objective of using districts was to facilitate the assignment of load zones to other objects in the power system such as new and existing projects.

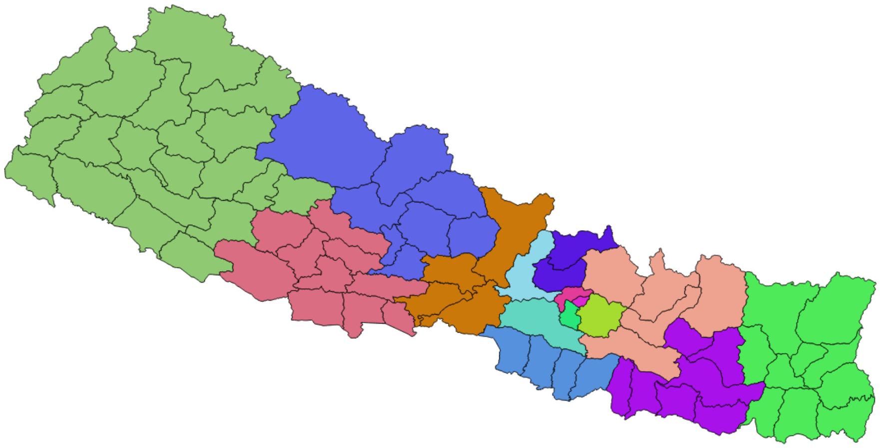

Figure 2.2.2 Allocation of districts to node clusters to produce administrative load zones

Load zone creation is then finalized by dissolving the district polygons in the shapefile and producing load zone polygons. Nepal has power exchanges with three Indian states: Bihar, Uttar Pradesh, and Uttarakhand. These three states are included as an individual load zone to simulate power exchanges based on the actual availability of the transmission corridors between Nepal and each Indian state (see Figure 2.2.3, Indian states shown hatched). These polygons will be used extensively for any spatially related assignment for power system entities in the model.

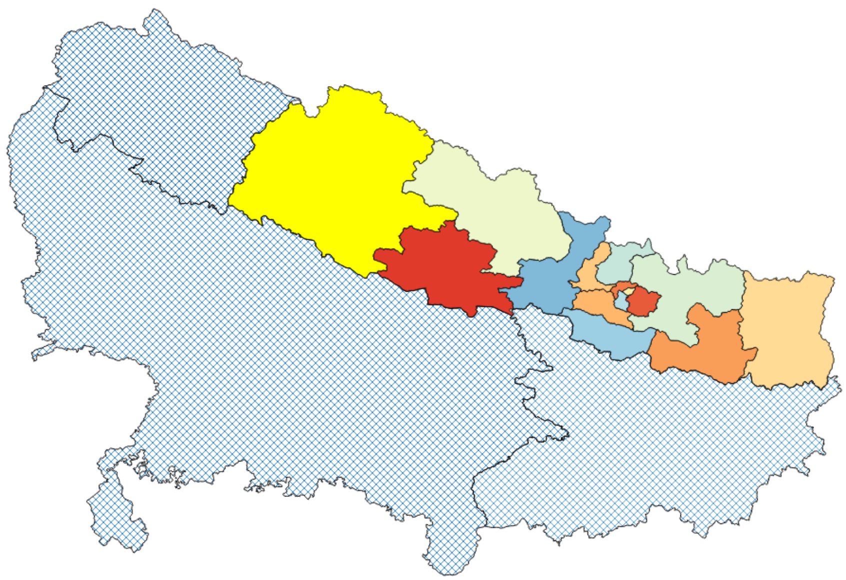

Figure 2.2.3 Definitive Nepal and India based load zones, with Indian states hatched for clarity

The SWITCH model uses a sampling method to represent the temporal dynamics of load and supply. The method is based on selecting a number of representative days of a typical year, and then selecting between 6 to 24 chronologically related hours per day as hourly samples. The SWITCH model then runs in two temporal resolutions:

- Investment periods: these are periods composed of several years that represent the points in time when the model makes investment decisions in generation and transmission. Each period is represented by a "typical year".
- Dispatch hours: a typical year is composed of many representative days that are further divided in chronologically related hourly samples. On each hour, the model determines the optimal or least cost dispatch decisions for generation and transmission assets that satisfy load and a host of power system technical constraints. The dispatch levels and mix are limited by the optimal investment decisions made by the model for a given period.

The hourly resolution of the SWITCH model requires producing load forecasts at the hourly level. The usual method has been to use a historical 8760-hour year profile and apply it to future periods. However, in the case of emerging economies, it is worthwhile to develop a bottom-up estimation that allows for the adoption of new types of end-uses.

We use a bottom-up approach and develop typical daily consumption profiles by customer segment for rural and urban residential, commercial, and industrial customers. These customer profiles are weighted based on the current mix of sales by customer type reported by NEA in their 2018/2019 Annual Report (NEA, 2019). We develop a "seasonal coefficient" to distribute demand differently across the year, and calibrate it based on average temperature: hotter months have a higher demand than colder months under the assumption that air conditioning will respond to high temperatures and that heating needs are not met using electricity. We then multiply these seasonally-adjusted and sales-weighted daily profiles by an average daily consumption based on existing electricity consumption forecasts to obtain hourly demand by customer segment.

A search for publicly available information revealed six available forecasts from two sources: one from the 2019 NEA Annual Report and five from the Electricity Demand Forecast Report (2015-2040) by the Water and Energy Commission Secretariat (WECS). This implementation uses the business-as-usual (BAU) scenario from the WECS, which was considered conservative. The method used relies only on the consumption (GWh) forecast, as the peak demand (MW) forecast is determined by the joint customer segment hourly profiles. In this implementation, the annual peak demand is about 4% higher than the forecasted peak demand for the WECS BAU scenario.

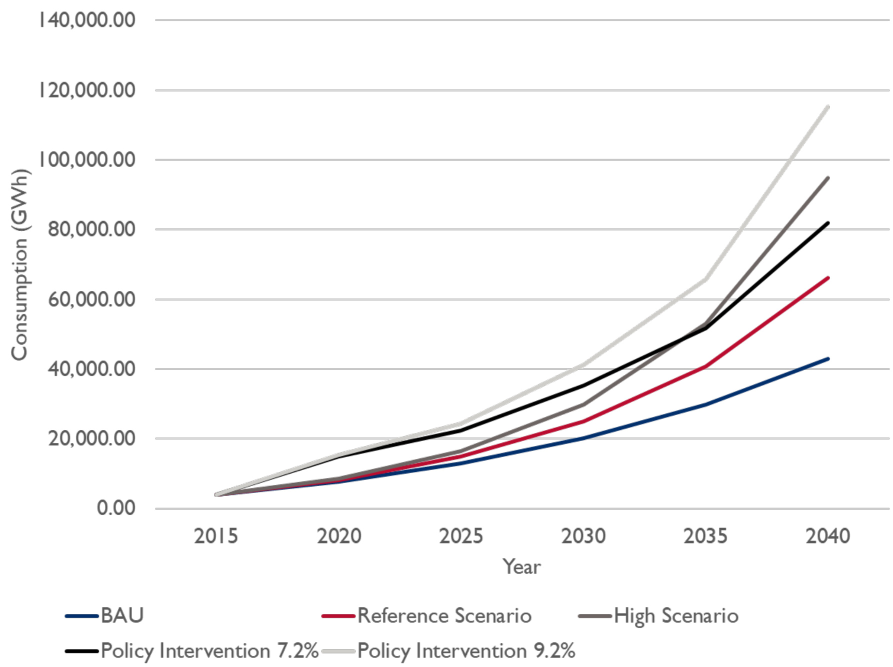

Figure 2.2.4 NEA and WECS load forecasts considered for this study

Finally, load has to be spatially allocated to the different load zones. The method employed relies on population by district to allocate residential and commercial demand, and then aggregating district population to load zone population based on the spatial mapping (see Figure 2.2.2). One advantage of this method is that allows incorporating latent and unserved demand into the forecast, rather than relying on historical data that covers only 50%-60% of the population. The population method is not appropriate to allocate industrial demand, which can follow a spatial pattern unrelated to population density. We use existing substation transformer capacity as a proxy for industrial demand location, by aggregating existing transformer capacity by load zone and then allocating industrial demand.

2.3 Transmission

Transmission data was available from a World Bank effort from 2013. However, the data seemed substantially inaccurate when compared to the most recent transmission system map available from the Nepal Electricity Authority (NEA, see Figure 2.3.1).

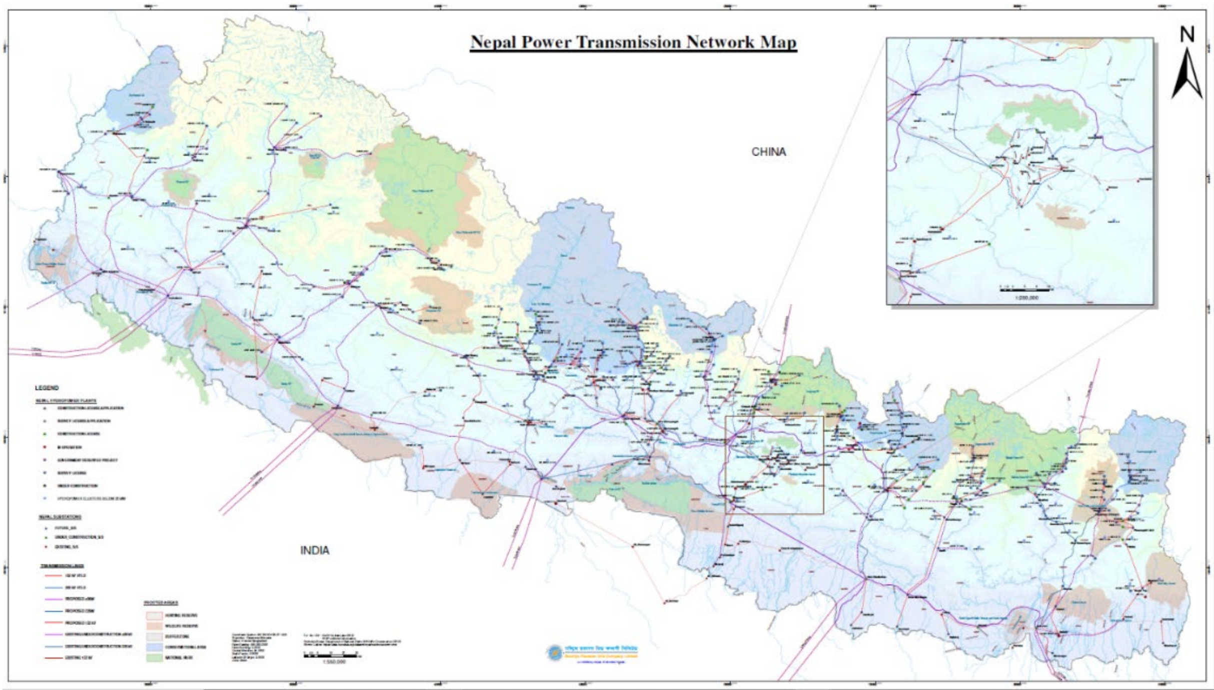

Figure 2.3.1 Nepal transmission network map

We produced our own spatial transmission data by georeferencing key substations from the original NEA map in Figure 2.3.1, and manually tracking the position of over fifty substations as reported in the latest 2018/2019 NEA Annual Report (NEA, 2019). This report also includes a list of existing transmission lines with basic electrical characteristics that were used to calculate its capacity rating in MVA. We transcribed all the transmission lines, associated them with start and end substations, and mapped them. Figure 2.3.2 shows the final transmission system resulting from this process.

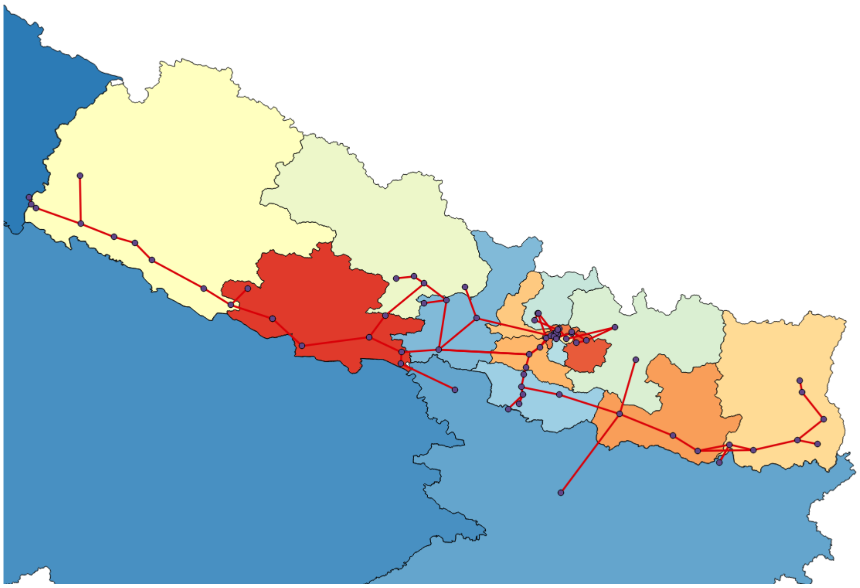

Figure 2.3.2 Main transmission lines extracted and georeferenced

With a spatially explicit transmission system, substations are assigned to load zones based on a spatial matching algorithm. Then, transmission lines that reside within a load zone are discarded, and transmission lines that connect different load zones are aggregated to produce a simplified transmission system (see Figure 2.3.3). This transmission system will be passed to SWITCH-Nepal to represent the main corridors and investigate future transmission expansion needs. Note that for visualization purposes, the existing substations are replaced by the load zone centroid. However, the real system preserves the lengths of the actual circuits to produce realistic estimation of line losses.

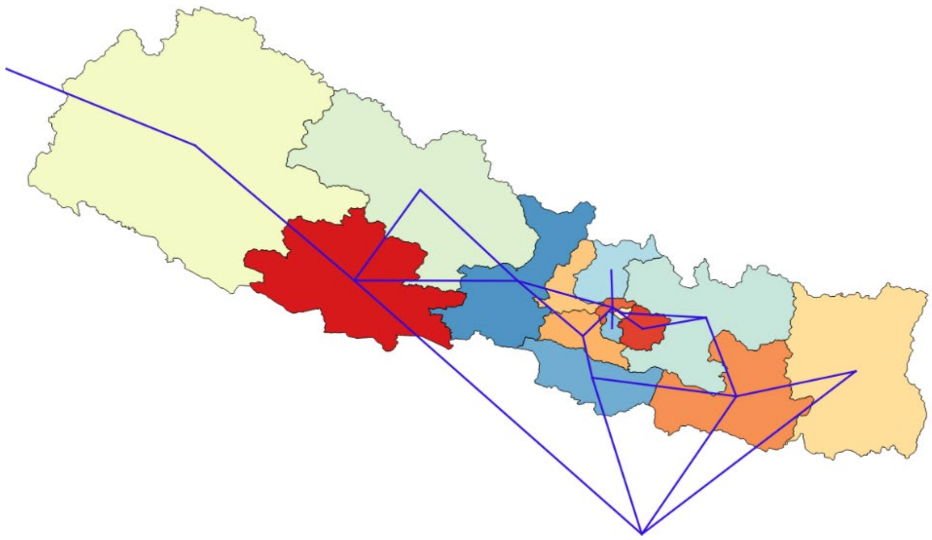

Figure 2.3.3 Simplified transmission system that serves as an input to the SWITCH-Nepal model

Future transmission corridors are also available in the 2018/2019 NEA Annual Report, reported as under construction, or planned. Most under construction projects in advanced stage were included when processing the existing transmission lines. Most planned transmission lines are repowering of existing corridors, upgrading from the standard 132 kV to 220 or 400 kV. This means that the corridor remains the same, but its losses will decline and capacity will expand. SWITCH-Nepal will expand transmission corridors as needed.

2.4 Supply side resources

This subsection provides information on the costs, location, and operational characteristics of the technologies that compose SWITCH-Nepal's portfolio: diesel generators, solar PV panels, wind turbines, battery storage, and hydropower.

Diesel generators and battery storage systems are modular, relatively easy to locate directly in substations, and are not resource-dependent. We allow the model to deploy diesel generation and battery storage on every load zone in the model. Investment costs for diesel generators come from EIA's 2020 Annual Energy Outlook (AEO, 2020), while investment costs for battery storage come from Cole et al. (2016). Diesel fuel costs were calculated based on a current cost of 0.76 $/lt and projected based on the crude oil forecast reported in the World Bank Commodities Price Forecast released in April 2020.

Investment costs for wind and solar PV technologies come from EIA as well and were compared to IRENA global average costs to verify they were representative of solar and wind projects (see Figure 2.4.1). We produced a set of lower costs for solar PV and wind based on the experience and expectations for development in India, which has a substantially more advanced renewable energy industry. The values were obtained from a very recent expansion pathways study developed for India in 2020 by NREL (Rose et al., 2020).

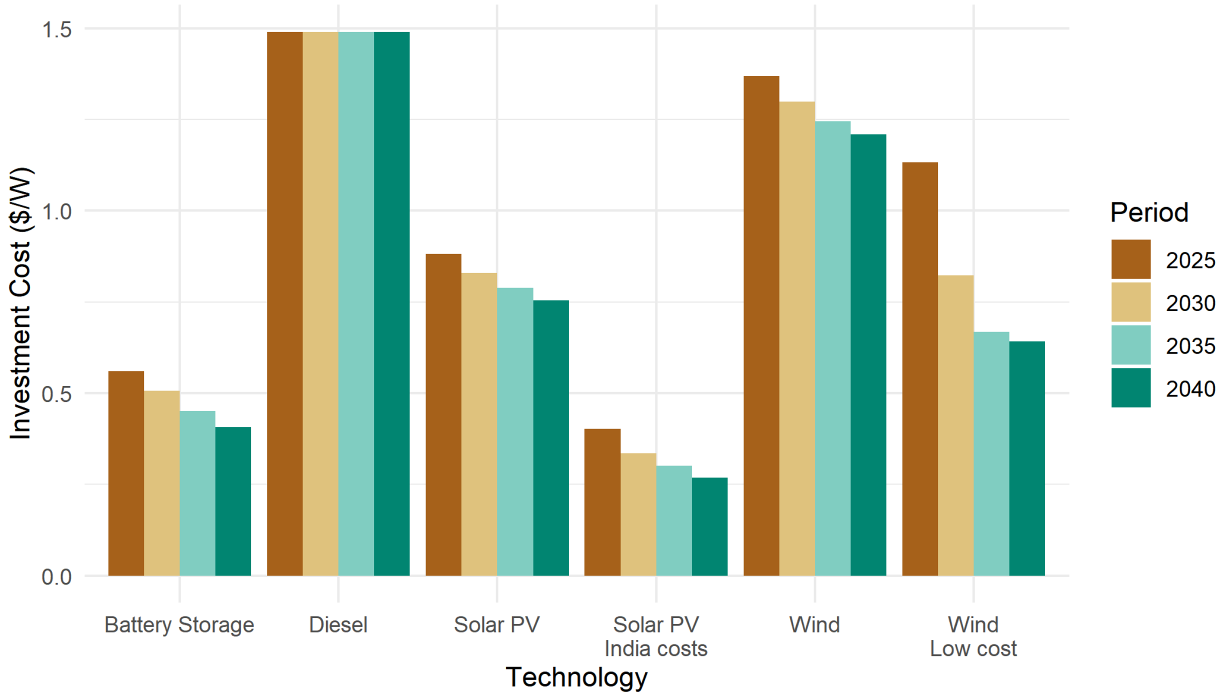

Figure 2.4.1 Investment costs for non-hydropower technologies

Finally, the import supply curve was calibrated based on the demand and price levels indicated in Table 2.4.1

Table 2.4.1 Import supply curve demand and price breakpoints

Demand level (MW)	Price ($/MWh)
0-2500	28.48
2500-2770	36.83
2770-3000	38.24
3000-3100	69.23

The values for this table were based on marginal cost outcomes of an India pathways expansion study (see Figure 2.4.2). We determined that supply curves for India presented a typical pattern of "breaks" that depended on the costs of coal, gas, and nuclear plants. We assumed that these values reflected the prices at which PPAs could be signed. We also assumed that Nepal would not be able to secure prices lower than $28.48/MWh, a reasonable assumption considering that for the SWITCH-Nepal model these imports are firmed (i.e. they include energy and capacity products).

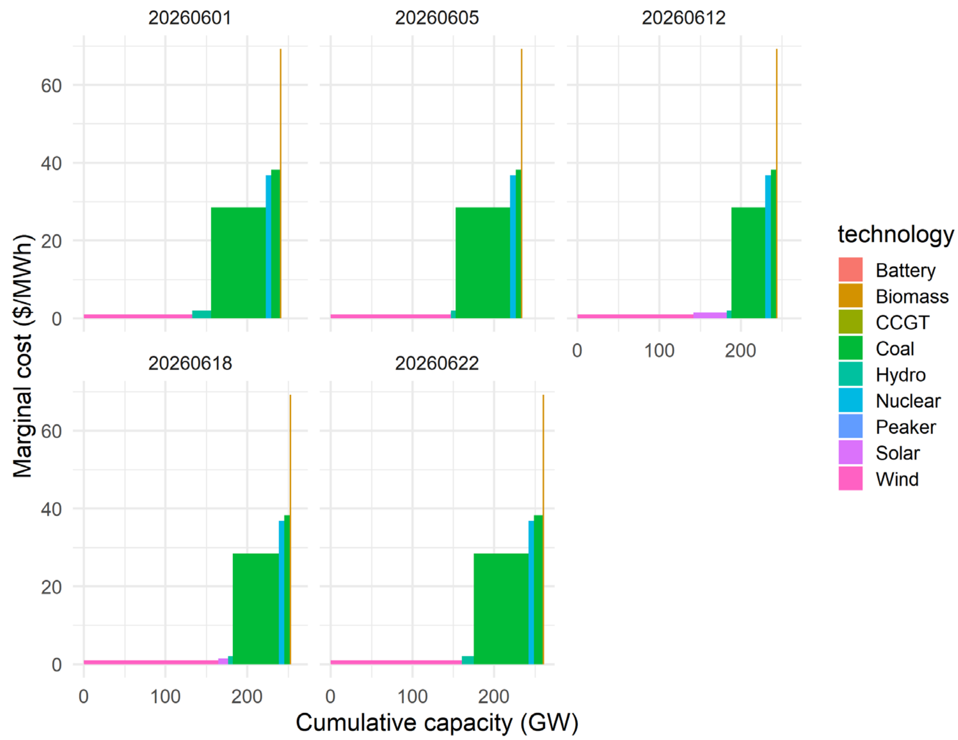

Figure 2.4.2 Example of supply curves for India for five hours for the month of June, 2026

2.4.1 Solar and wind resource

We developed our own systematic, GIS-based approach to select the most appropriate locations for solar and wind farm development due to the lack of detailed studies with publicly available resource data evaluating solar and wind potential in Nepal. The suitability of both solar and wind site selection are driven by resource potential, surrounding geography, and proximity to existing populations and grid infrastructure. Therefore our analysis began with the overlaying of a digital elevation model (DEM) raster separately with a solar resource raster and a wind resource raster.

Solar resource was quantified by PV electricity output in kWh/kWp at a 1km resolution. This can be interpreted as the average daily photovoltaic electricity (AC) delivered by a PV system and normalized to 1 kWp of installed capacity. Elevation data was aggregated from 90 meter resolution to 1 km resolution using the mean value and variance (as a proxy for slope or incline). The result was a 483,140 cell raster of elevation, elevation variance, and PV output at approximately a 1km-by-1km resolution across Nepal. Cells were then ranked by highest PV output, minimum elevation variance (and under an elevation variance cutoff), and under cutoff for elevation. Cutoffs were informed by Guaita-Pradas et al. (2019) which notes that ideal sites are located below 5800m in elevation and on flat terrain or gentle slopes facing south with less than a 5% graded slope. Promising cells were sequentially investigated using Google maps's satellite imagery for proximity to existing or planned substations, proximity to existing or planned transmission networks, proximity to existing populations, minimizing disruption to existing built infrastructure and cities, avoiding protected lands in National Parks and Reserves, avoiding the steep and inaccessible terrain of the Himalayas, and with a slight preference towards geographic diversity. Therefore open fields on relatively flat surfaces surrounding major population centers were found to be the most promising sites. Through a sequential and systematic approach we identified 30 suitable 1km-by-1km cells that could each install approximately 30 MWac solar (NREL, 2013). The majority of the sites were clustered in four regions surrounding Tulsipur, Surkhet, Pokhara, and Kathmandu (see Figure 2.4.3). Hourly capacity factors for the selected solar sites were simulated from the MERRA-2 global solar dataset with 1-axis tracking, 30 degree tilt, and a system loss fraction of 0.1.

Wind resource was quantified by mean power density (W/m2) at 150m hub height at a 250m resolution. Both elevation and wind resource data were aggregated to 2km-by-2km resolution using the mean value and variance of each. Elevation variance served as a proxy for slope or incline, and wind resource variance served as a measure of the consistency of the resource across an entire wind farm. The result was a 109,745 cell raster of elevation, elevation variance, wind resource, and wind resource variance at approximately a 2km-by-2km resolution. Cells were ranked by the highest wind resource and lowest wind resource variance, while removing the high-extreme values of elevation and elevation variance. Similar to the solar site selection, promising cells were sequentially investigated using Google Maps' satellite imagery for proximity to existing or planned substations, proximity to existing or planned transmission networks, proximity to existing populations, minimizing disruption to existing built infrastructure and cities, avoiding protected lands in National Parks and Reserves, and avoiding the steep and inaccessible terrain of the Himalayas. Through our approach, we identified 21 suitable 2km-by-2km cells for wind farm development. The majority of the cells were clustered along the border with India between Shivapur and Lumbini in areas with farmland interspersed with small village clusters (see Figure 2.4.3). All locations were within 25-30km away from existing or planned transmission lines.

In order to simulate hourly capacity factor for the selected sites we first had to determine an appropriate turbine for the solar resource. We tested all 130 turbines available on Renewables.ninja's at a representative location for the sites selected using the MERRA-2 (global) wind dataset at 1MW capacity and at a hub height of 150m. The five models with the highest total mean capacity factor were: Goldwind GW140 3000 (30.3 %), GE 1.7 (29.9 %), Vestas V110 2000 (29.0 %), Goldwind GW121 2500 (28.8 %), Goldwind GW140 3400 (28.2 %). The maximum mean capacity factor for all five of these models was found at a hub height of 150m. CF decreased with decreasing hub height and at 120 m, the CF were about 6-7% less than at 150m.

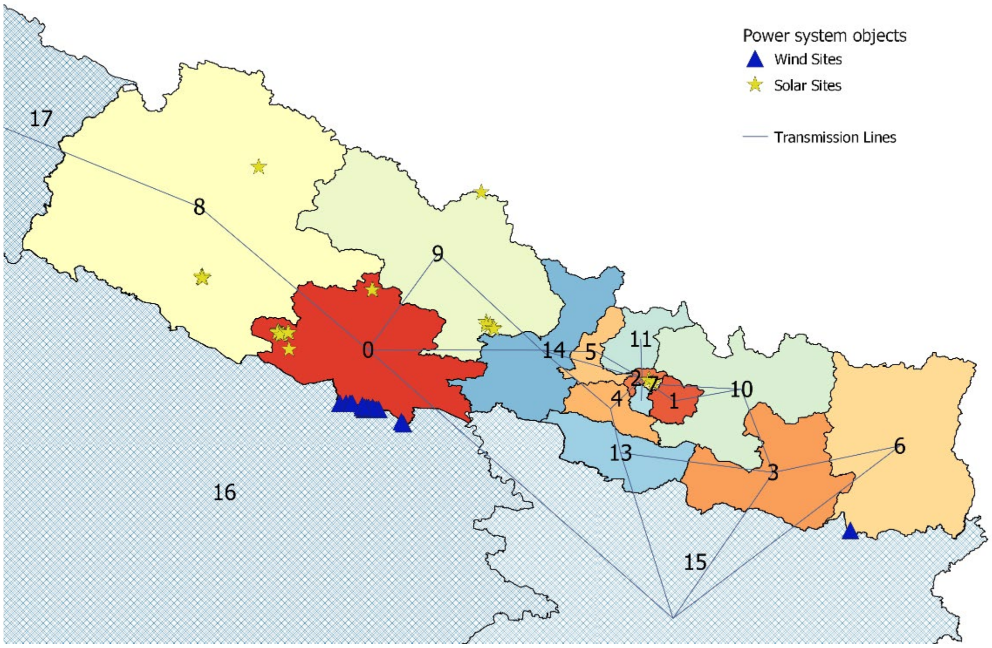

Figure 2.4.3 Wind and solar site location

Detailed information on the solar and wind site selection process can be found in Appendix C.

2.4.2 Hydropower

As indicated in section 2.1, hydropower projects were collected from an array of sources that included the Government of Nepal, the Tractebel study, and newspaper and trade magazine articles. The final set of 1359 projects was input in the SWITCH-Nepal reference scenario and, by default, in all other scenarios that do not constrain hydropower development. The location of these projects by unit type is shown in Figure 2.4.4.

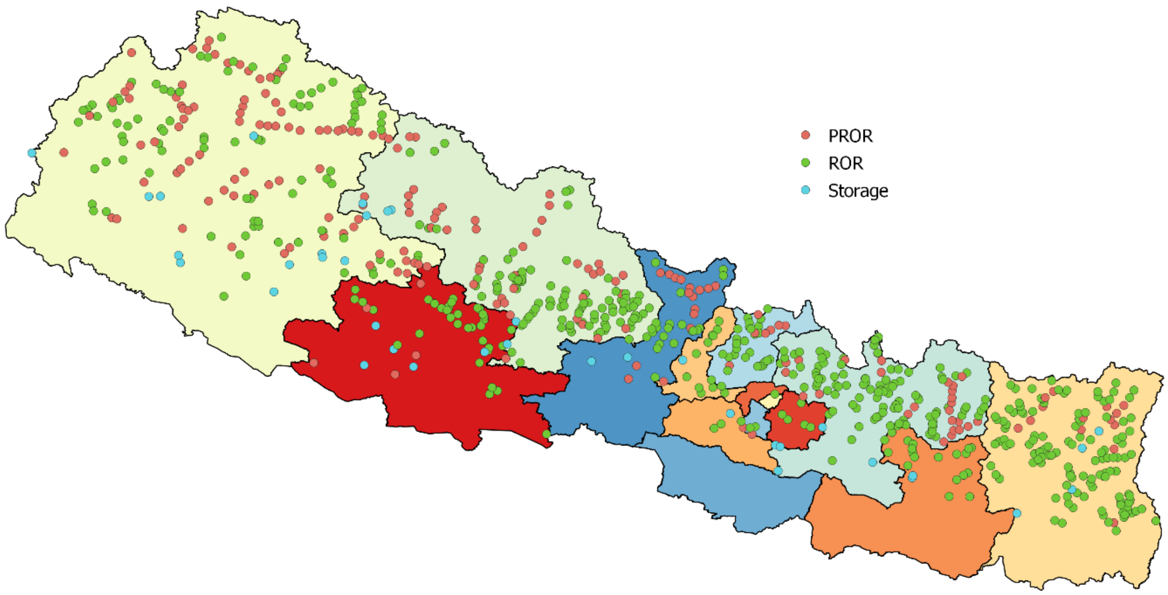

Figure 2.4.4 Location of hydropower projects in Nepal

Final costs for hydropower projects vary by project, rather than by technology. This approach was developed to capture the wide range of costs that characterize these types of projects given geographical constraints. The range of costs for the different hydropower unit types is shown in Figure 2.4.5. The relatively higher costs for ROR units is due to their lower capacity compared to PROR and storage projects and the consequent lower economies of scale.

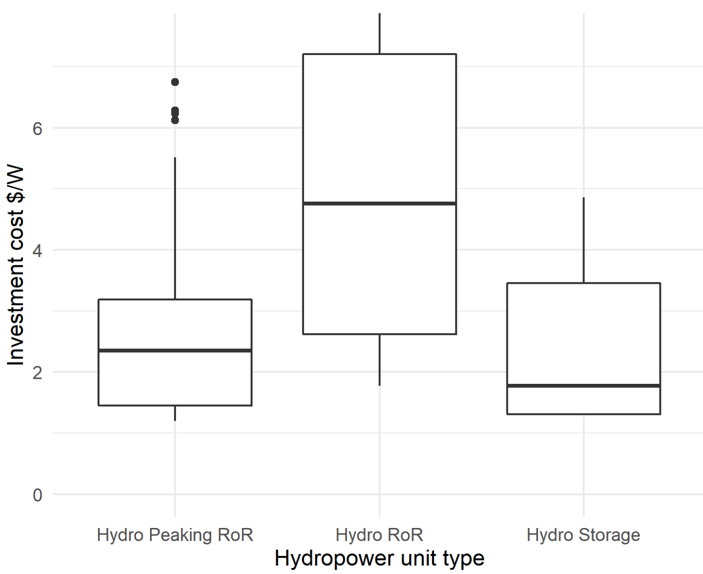

Figure 2.4.5 Hydropower cost distribution by unit type

3 Scenarios

This section is based on Report #3 – Scenario Development, released in July 2020. However, we have made changes to the original scenarios to reflect final decisions made at the modeling stage, and also to finalize decisions that were reported as pending in the original report #3. A detailed list of every scenario developed for this study is included in Table A.1.2 in Appendix A.

3.1 Background on scenario analysis

Long-term planning models like SWITCH-Nepal are best employed for scenario-analysis. Projections 20 to 40 years into the future are not predictions because there is no empirical scenario to compare them against to estimate a priori the accuracy of these predictions. In scenario-based analysis, simulation outcomes for specifically designed scenarios are compared to each other. Typically, one of these scenarios is established as a reference and compared to other scenarios to identify the effect that specific changes have on model outcomes. Then, scenarios must be created by changing few and selected components to understand their impact.

Several types of components can be modified to produce scenarios. For example, numeric input values such as the cost over time for a given technology or for a fuel cost can be changed to test the sensitivity of the simulation outcomes. Alternatively, the SWITCH linear program can be constrained or relaxed to create scenarios. In a linear program, adding or relaxing a constraint will produce different outcomes if that constraint is binding. For example, one can add constraints to limit the volume of imports, or the total capacity to install for a specific technology. One can also remove or adjust constraints to meet certain reliability levels, or prescribed ecological flows downstream of reservoirs. Generally, relaxing or eliminating constraints in minimization problems should lead to lower values of the objective function (i.e. lower costs), while strengthening or adding constraints should lead to higher values (i.e. higher costs). We use this strategy to create several of the scenarios used in the EOA.

3.2 Scenarios

Table 3.1 includes ten scenario groups (SG) and the reference case. Each SG is composed of several individual scenarios – model instances – that implement a specific condition or assumption to be tested. In this context, each scenario corresponds to a specific model simulation. The table also reports the expected policy application for each scenario group, linking the simulation outcomes to policy relevant issues for the Nepali power system. Each scenario group is described in more detail as follows.

Table 3.1 Scenario group description and policy application

Scenario group ID	Scenario group name	Scenario group description	Policy applications
0	Reference	This scenario reflects consensual expectations on costs, project availability, and policies that would affect any future development pathway.	General guidelines for power system expansion under expected conditions.
1	Karnali	Eliminate or constrain future development of hydropower projects in the Karnali Basin	River conservation policy for the Karnali basin that uses a system approach to assess the cost and benefits of these conservation decisions.
2	Limited Hydro	Constrain hydropower expansion across Nepal, with no basin-specific limits	River conservation policy for Nepal that uses a system approach to assess the cost and benefits of these conservation decisions. Cost assessment of the impacts of potential exogenous (i.e. non-modeled) factors that would hinder hydropower development, such as access to financing, political stability, etc.
3	Low-impact Hydropower	Use SSP to produce low-impact and cost-effective hydropower portfolios	Demonstrate how low-impact hydropower projects that are relatively cost effective can be attained by combining two models. This scenario was not implemented in this study, but it is presented to consider its exploration in future work
4	Expansive Hydropower	Remove alternative resource options for a hydropower based expansion	Understand the costs and risks of focusing on a single technology and not actively pursuing emerging technologies such as wind, solar PV, and battery storage, as well as existing imports. Note that the risk assessment would have to be an out-of-model calculation.
5	Non-Hydro Renewables	Produce scenarios that explore high future dependence on non-hydropower renewable resources	Produce an estimate of the costs and operational challenges of limiting hydropower resource development by requiring higher quotas for non-hydropower renewable resources.
6	Energy Independence	Constraint or eliminate imports from India, or modify financial conditions from those imports	Cost and operational impacts of reducing or eliminating imports and power system response to restrictions on imports. These may then be compared to the potential benefits of such strategy.
7	Export Strategy	Understand how the Nepal power system would look if it had to serve additional load for exports	Cost and operational impacts of pursuing an expansionary strategy to serve other markets beyond Nepal. These costs may be compared against out-of-model revenue calculations coming from export sales under different price scenarios.
8	Batteries vs PROR	Compare the cost-effectiveness and operational applications of both short-term storage methods	Identify the cost levels and timing at which battery storage may be a preferred resource adequacy solution compared to PROR. This may help prioritize hydropower project development to steer away from PROR projects.
9	High Hydropower Costs	Hydropower development more expensive than the BAU	Measure the power system response to higher costs than anticipated on hydropower projects, due to project complexity and cost overruns. This would help identify "borderline" projects that leave an optimal portfolio given cost increases, and focus development on projects that are robust to cost increases.
10	Regional Equity	Projects should be developed and benefit all regions in Nepal	Inform regional development targets and the potential costs of "forcing" projects to be developed in areas that for have substandard resource quality and/or availability.

3.2.1 SG-0 – The reference scenario

As indicated, one of the primary uses of scenario-based tools like SWITCH is to produce a reference scenario. This scenario reflects consensual expectations on costs, project availability, and policies that would affect any future development pathway. The reference scenario was defined jointly by the project team prior to starting the simulation process to reflect current expectations from Nepali stakeholders, and cost and market trends for investments and fuels.

3.2.2 SG-1 – Karnali

This SG includes several scenarios that explore different constraints to future hydropower development in the Karnali basin. Typically, technology-constrained scenarios are produced by limiting the total installed capacity through the simulation horizon, the total amount of generation coming from this technology, or the share of this technology's capacity or energy with respect to the whole generation fleet. These are collectively known as electricity-based constraints. In the case of a focused study like this, we can also include project-based constraints using additional criteria to select or exclude projects.
As indicated, a first set of scenarios explores non-hydrologically constrained options:

- A scenario that excludes any hydropower project to be developed in the Karnali basin
- A scenario that excludes any storage hydropower project to be developed in the Karnali basin

A second set of scenarios employs extended project data to exclude projects based on location criteria established through hydrological impacts. Setting up these scenarios would require expanding project characteristics to identify the river in which each project would be installed, probably using information collected for the HCV river assessment:

- A scenario that only allows deployment of projects in secondary river stems, but not on the Karnali mainstem
- A scenario that keeps all four tributaries of the Karnali free flowing, in addition to the mainstem
- A set of four scenarios that keeps at least one tributary of the Karnali free flowing.

In this scenario group, the rest of the system (i.e. the non-Karnali basin power system) is modeled as the base case scenario with no specific constraints.

3.2.3 SG-2 – Limited National Hydro

This SG is an extension of SG-1, applying similar hydropower development limitations to the whole country, rather than a single basin. Similarly as SG-1, scenarios that limit hydropower development can do so by imposing a maximum capacity to be developed or a maximum total generation or share of generation with respect to the system. The model would then be able to select any cost-effective combination of projects that meets these constraints and maintains system reliability.

An alternative approach to constrained hydropower development is to implement a hydropower moratorium, either by preventing the model to deploy any hydropower, by preventing deployment of certain hydropower technologies, or by allowing deployment from a certain year in the future. These constraints are extreme and not intended to represent reality, but to provide the policy maker a sense of the impact that technology availability has on the power system.

Scenarios in this scenario group include:

- A set of scenarios that explore simple countrywide installed capacity limits set at fixed percent of peak demand (10%, 25%, 50%, and 75% of peak demand)
- A scenario that prevents any new hydropower development in Nepal (full moratorium)

Following the ideas in SG-1, we also explored scenarios that are focused on free-flowing rivers across the nation. These scenarios were produced using input from the HCV analysis to identify projects that would be located in rivers that have already been intervened, and limit the portfolio to those.

- A scenario with no development in rivers that are classified as free-flowing as a result of free-flowing river analysis. Dam development on stretches with "good connectivity" is still possible.
- A scenario where projects can only be developed in rivers that have an aggregated HCV value below or equal to 1. In this scenario, dams could be developed on rivers that are free-flowing.
- A scenario where projects can only be developed in rivers that have an aggregated HCV value below or equal to 2. In this scenario, dams could be developed on rivers that are free-flowing.
- A scenario that does not allow development in "benchmark" rivers. "Benchmark" rivers are rivers which match the definition of HCVR according to the experts (Karnali, Humla Karnali, Budhi Gandaki, West Seti and Tamor). Some other rivers have been added in this scenario based on the importance of those rivers for biodiversity (Tila, Bheri, East Rapti, Thuligad, Babai, Thulo Bheri)
- A scenario that prevents development of hydropower projects in protected areas.
- A combination of the two previous scenarios.

3.2.4 SG-3 – Low Impact Hydro

A complementary approach to SG-2 uses the SSP model to find hydropower portfolios across Nepal that balance low impact with cost-effectiveness. The purpose of SG-3 is to assess SWITCH hydropower portfolios in SSP to measure their impact level on several metrics, and then to assess the cost-effectiveness of low impact hydropower portfolios from SSP in SWITCH. As indicated, this SG was not developed for this study but it is presented for consideration for future work.

This SG is separated from SG-2 as it employs a method that looks to interface SSP and SWITCH, rather than just tweaking constraints in the latter. This method follows this general procedure:

1. Start with an unconstrained SWITCH run, which produces a least-cost combination of hydropower resources by 2040.
2. Assess the impact of these resources in SSP using the HCV framework. Depending on the impact level, SSP suggests one or more new combination(s) of hydropower resources that has lower impact, or that achieves a pre-determined impact level. The SSP combination of resources should produce similar amounts of energy, or have similar firm capacity.
3. Identify the common hydropower projects across both the least-cost (SWITCH) and low-impact (SSP) portfolios.
4. Prepare a new SWITCH run in which the common projects are "fixed" in the SWITCH model, entering operational service based on the original SWITCH run from #1. Run the SWITCH model again with these "fixed" decisions, letting the model decide the remaining expansion.
5. Assess the new output in SSP, as in #2, and iterate through #3-#5.
6. When all projects are fixed, the resulting portfolio can be deemed as an impact and cost balanced set of projects.

It is important to note that the above procedure has yet to be properly tested, and this is recommended as a focus area for future work. There is a possibility that the iterative approach will not converge into a set of "fixed" projects.

3.2.5 SG-4 – Expansive Hydropower

This scenario group is composed by a single scenario (run as MILP and as LP) that would represent the current position of some Nepali stakeholders that the domestic power system mix should be based exclusively on hydropower. This scenario removes from the portfolio any non-hydropower projects, leaving only ROR, PROR, and storage projects eligible to meet demand by 2040. The results of this SG will provide a least-cost investment pathway for hydropower resources, which could be useful to prioritize an investment pipeline of hydropower projects.

This scenario can also be run in combination with the hydropower assumptions from SG-9 to understand the risks of higher hydropower costs than anticipated on a hydro-only expansion pathway.

3.2.6 SG-5 – Non-Hydro Renewables

SG-5 explores power systems that substantially reply on non-hydropower renewable resources available in Nepal. Generally, given the available resources for generation in Nepal, hydropower constraints such as those implemented in scenario groups 1, 2 or 3 will trigger substitution of hydropower by other available technologies such as wind and solar. In SG-5, more explicit

targets for wind and solar are tested to explore outcomes that are not driven by unavailability of certain hydropower resources.
Scenarios for this SG include:

- A set of scenarios that implements a renewable portfolio standard (RPS) that attains 20%, 35%, and 50% of power coming from non-hydropower renewables by 2040.
- Choose the 50% RPS level and apply sensitivities on future cost trajectories by testing a low and a very low cost projection.

The purpose of these scenarios is to demonstrate that a power system that does not substantially depend on hydropower is possible for Nepal. These scenarios will also benchmark the costs and operational characteristics of an alternate expansion pathway for Nepal.

3.2.7 SG-6 – Energy Independence

This SG explores the consequences of policy decisions aimed at reducing or eliminating imports from India to achieve electricity production independence. In scenarios in this scenario group the "energy banking" logic is disabled and replaced by a direct constraint on import levels. There is a direct and an indirect method to achieve import constraints:

- Direct (quantity strategy): constrain the volume of imports by imposing an annual, seasonal, or hourly limit. This is equivalent to assuming transmission lines from India would not be expanded, and hence would constrain imports, but can also be the result of political decisions from either country.
- Indirect (price strategy): the supply curve for the India market can be calibrated to simulate higher or lower average prices for imports. The model would naturally expand or contract its import volumes in response to these prices.

For simplicity, a direct or quantity strategy is employed. As indicated, there are several methods to limit imports from India, and these methods can be implemented jointly. This scenario group implements two joint constraints:

- A <u>total annual</u> limit on energy imports, expressed as a share of total energy consumption on each year.
- An <u>hourly limit</u> on imports, which would resemble a hard limit resulting from transmission line constraints. This scenario would reveal the impact of import restrictions for resource adequacy (i.e. meeting peak demand), which will be different from the energy impacts.

The annual and hourly limits are linked by making the hourly limit be four times the annual limit. We test three import limit scenarios set at 0%, 10%, and 25% of annual energy needs (i.e. 0%, 40%, and 100% (no limit) of hourly needs). As will be demonstrated in the results, the 25% constraint is actually higher than the energy banking equilibrium in the reference scenario and results in a scenario with lower costs.

3.2.8 SG-7 – Export Strategy

SG-7 explores the evolution of the Nepal power system under a strategy to export part of its production to neighboring countries. SWITCH is a cost model, so it cannot simulate market exchanges. Therefore, an implementation for an export strategy involves adding demand to the India load zones, which could be served by exports from Nepal. Previous work explored cross-border exchanges between Nepal and India, which provides basic benchmarks for calibration of these scenarios (e.g. McBennett et al., 2019; SARI/EI, 2017; Timilsina et al., 2015)

The export strategy SG implements an alternative to the energy banking import strategy that requires the net exports to be a certain percent of annual domestic consumption. For demonstration purposes, we test a scenario with a 50% export requirement and a scenario with a 100% export requirement.

Proper assessment of the cost impacts of this scenario group requires calculating the potential surplus revenue that would be raised from the sales of these exports. Rather than calculating a specific price for export revenue calculation, we use three different price levels to value exports at 20 $/MWh, 30 $/MWh, and 40 $/MWh and present results for each. These values are based on the import supply curve calibration prices presented in Section 2.

3.2.9 SG-8 – PROR vs Battery Storage

Nepal relies on PROR plants to provide load following service in its system. PROR plants can have higher impact due to inundation of a larger reservoir area and more variable downstream flow releases, and require more infrastructure than a ROR plant with equivalent energy production.

A potential strategic decision would be to assess whether to incur the additional costs that a PROR project would have - compared to a standard ROR project - or whether to deploy battery storage to provide that flexibility. Cost reductions in battery storage may make this resource cost-effective for large-scale adoption in power systems, with substantial benefits. This decision may be contingent on the location of potential PROR projects, as well as the timing for cost declines in battery storage.

Two scenarios are developed in this group:

- In the first, PROR plants are included as in the reference scenario, but no battery storage is allowed to be deployed.
- In the second, PROR plants are treated as regular ROR plants and battery storage is allowed. The idea of maintaining the same plants is to keep their energy contribution constant, but remove the "flexibility" contribution from the peaking ROR to assess its impact.

The two scenarios have the same available energy and same demand, which means differences reflect the comparative value of storage in PROR ponds vs storage in batteries to the power system. By comparing these scenarios between themselves and against the reference scenario, we will be able to determine the value that PROR and battery storage technologies bring to the power system in Nepal.

3.2.10 SG-9 – High Hydropower Costs

Recent research has demonstrated that hydropower projects have typical cost overruns of 33% of the original projected cost (Braeckman et al., 2019). Another report that examines budgets for mega-dams and compares them with actual outcomes suggests up to 100% cost overruns for these projects (Ansar et al., 2014). The Bhutan Electricity Authority recently reported cost overruns of between 40% and 170% for ongoing projects in the country (BEA, 2017). These cost overruns could have substantial economic impact in countries like Nepal that are planning system expansion primarily based on hydropower.

This scenario group will explore two approaches. The first is an out-of-model calculation that estimates the actual system costs should the hydropower projects from SG-0 (the reference scenario) and SG-4 (the Expansive Hydro scenarios) cost more than originally anticipated. An out-of-model calculation prevents SWITCH from making decisions based on costs, effectively estimating the impact of sunk investments without recourse. The second approach is a SWITCH run using an increased cost of hydropower in which the model will make different investment decisions based on the new higher costs of hydropower projects. We use a 25% and a 50% increase in costs across all hydropower projects.

It is worth noting that projects can also be more expensive if they take more time to develop. The paper by Braeckman et al. (2019) determined that projects took on average 20% more time to finalize than estimated. This would add one or two years to the project development, incurring in higher financing costs due to immobilized capital and foregone sales. However, for simplicity this SG will only use a cost expander to assess the impacts of higher costs in hydropower projects.

3.2.11 SG-10 – Regional Equity

Policy objectives in many emerging economies, including Nepal, strive for relative equality in the distribution of project benefits (and potentially, costs and environmental and social impacts). This objective usually translates into regional quotas for project development that can be measured in installed capacity, energy production, project investment levels, royalties/taxes/dividends, or employment, among others. The benefits of these regional equity policies are difficult to measure, but estimating their cost compared to a non-policy scenario would give a benchmark of benefits levels that would achieve net social welfare gains.

Load zones in the SWITCH model – the minimum unit of spatial analysis in the model – are composed by clusters of districts. Then, load zones can effectively represent political subdivisions within Nepal and are amenable to be used for regional equity analysis. We explore a set of scenarios in this group where we require minimum levels of installed capacity in each period for each load zone as a percent of the load zone's peak demand. We test levels of 10%, 20%, and 50% of local peak demand as minimum installed capacity for each load zone.

4 Results

The results section is organized based on the scenario groups and the policy issues that they study. We usually report the capacity mix, cost, and hourly dispatch for each scenario group, and discuss the policy implications of these findings.

4.1 Interpreting cost-based results

One of the main results from the SWITCH model are the costs to build, maintain, and operate the power system. It is important to understand what these costs reflect and do not reflect and what cost differences mean. It is also important to remember that SWITCH is not a market model. Hence, the model does not produce prices and does not verify that investment is profitable through market exchanges (in the model, each project and transmission line earns a "regulated" return on investment that is quantified as a cost). This is equivalent to assuming that investment and operation of assets is regulated or government owned, both of which apply reasonably well to the Nepal case.

First, the SWITCH model captures the main sources of cost in a power system. The results reflect the investment costs, including financing costs and return over investment of building generation, transmission, and distribution. Due to lack of available data, the model does not account for the costs of existing transmission and distribution infrastructure. This is not important for our purposes because we analyze monetary results as the difference against the reference scenario. In addition to investment costs, the model reflects typical operational costs such as variable fuel costs, variable non-fuel costs, and fixed annual costs for generation; operational and maintenance cost for transmission and distribution systems; and ancillary services costs to maintain spinning, non-spinning, and quickstart reserves. All costs are discounted to the present year using a 7% discount rate.

Second, the expected inaccuracies of a power system modeling tool are such that a difference of less than 1% may not be statistically significantly different from 0 when comparing costs between scenarios. When interpreting cost results, readers are advised to consider cost differences under 1% as negligible for policy making purposes.

It is useful to put cost differentials in context. We can perform a simplified calculation to estimate the equivalent cost increase in % with respect to the reference scenario in dollars per household. The reference scenario produces an average all-in rate of 9.8 cents/kWh. The average monthly household income in Nepal was about $250 in 2015 (CEIC, 2015), estimated $300 in 2020. Assuming an average household consumption of 150 kWh per month, households would spend about $15 per month in electricity or 6% of their monthly income. Then, a 2% increase in cost equals to 30 cents per month.

A final note on interpretation of cost results relates to the role of energy banking on determining import and exports, and the subsequent impact on cost. Depending on the choice of scenario, the available annual energy surplus from hydropower and other resources will differ. This surplus determines the optimal level of imports allowed, but will also typically drive up costs. These costs could be mitigated through export revenue. However, for simplicity we do not calculate export revenue with the exception of SG-7, the export strategy scenario group. The reader should take into account that scenarios that have a higher level of imports and exports may mitigate costs with higher revenue from these additional exports (import costs are always accounted for).

4.2 The reference scenario

The reference scenario is the least constrained scenario that uses a basic set of assumptions for existing and future infrastructure, costs, and imports. As indicated, the purpose of the reference scenario is to set a benchmark against which the scenario results can be assessed. It is not relevant that the reference scenario perfectly predicts the most likely evolution of the Nepali power system; that is indeed impossible. It is important that the cost, project, and other forward-looking assumptions applied to the reference scenario are reasonable. We believe this is the case, based on our research and stakeholder interactions.

It is also important to recall that the model is ran as a MILP in some cases and as a LP in other cases. Therefore, there are two reference scenarios, one for each model solving approach. In practice, both reference scenarios are very similar in their resource mix, operation, and costs. In this section we share the results of the MILP reference scenario.

The reference scenario capacity expansion is mostly based on PROR and ROR plants, and imports. However, while PROR expands from 1.9 GW in 2025 to 7.8 GW by 2040, there is no expansion of ROR plants from the existing 1.3 GW. Wind generation is profitable from the first period, with a small 3 MW installation, but growing to almost 1 GW by 2040. Flexibility to follow load is important in a power system and the model deploys battery storage and diesel generators to provide peak power and intra-day balancing. Battery storage is deployed starting in year 2025 with 80 MW, increasing to 300 MW by 2040, while diesel capacity increases from 170 MW to 900 MW in the same periods.

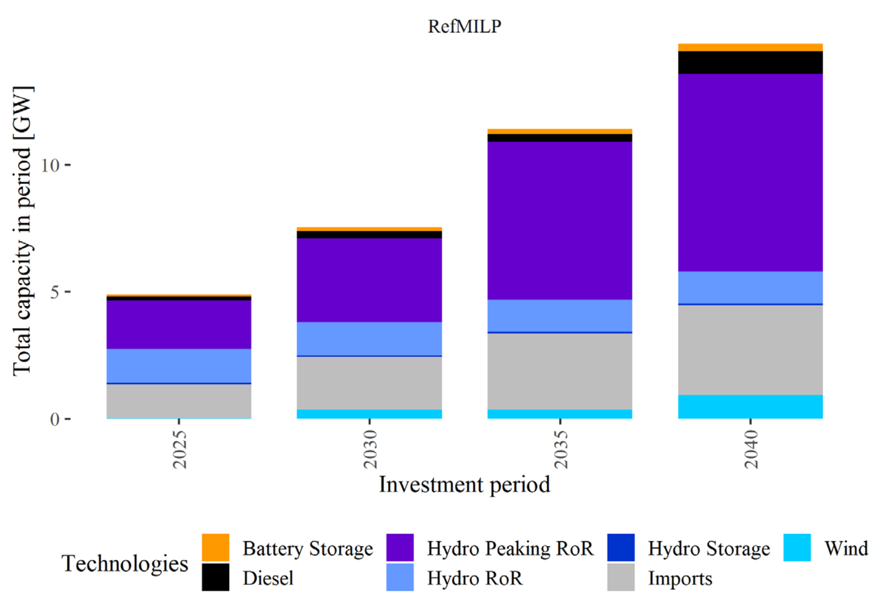

Figure 4.2.1 Capacity expansion for reference scenario

It is important to note that capacity deployment does not reflect actual energy production, which is the result of optimal dispatch decisions by the model. Figure A.2.1 in the Appendix shows the evolution of the production mix for the country. About 75%-80% of the annual energy is produced from hydropower, with the remaining 20%-25% is supplied by a mix of imports and wind energy. As expected, the use of diesel plants is minimal, accruing less than 0.1% of energy in the year from their sporadic use as peaker units.
Imports from India provide a significant share of capacity and energy. The energy results show that the optimal level of imports under an energy banking logic are between 21% and 25% of energy needs per year. Imports play a fundamental role in balancing seasonal availability of hydropower and, as we will see in the results for SG-6, in reducing the costs of achieving this annual balance to meet demand at high levels of reliability. Figure 4.2.2 shows the hourly dispatch for each of the twelve days simulated for the 2025 investment period. Each header codes the year, month, and date in an YYYYMMDD format. In the wet months of May, July, and September production from hydropower plants is significantly higher than load in the majority of hours in the day. This surplus is available for exports. Following the energy banking strategy, the model uses imports to reliably supply power during the dry season. In dry season peak hours, more than half of the capacity required to meet load at the national level is provided by imports.

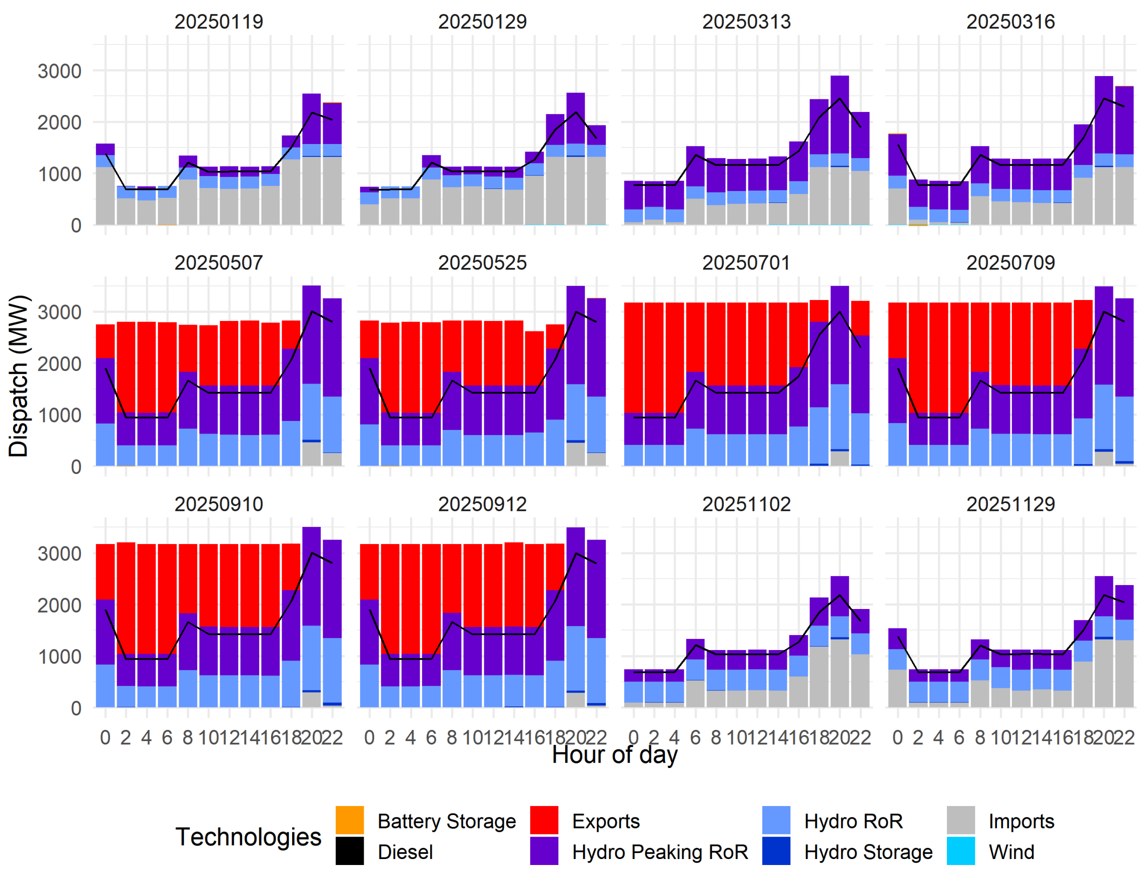

Figure 4.2.2 Hourly dispatch for each of the twelve days simulated for the 2025 period.

The reader will notice the remarkable absence of storage hydropower projects in the reference scenario investment decisions. In addition to the modeling limitations mentioned in Section 2, we believe that the lack of deployment of storage hydropower is due to two additional factors. First, these plants tend to be much larger than ROR and PROR plants and in many cases capacity of a single storage plant can be a substantial fraction of load. These capacity characteristics reduce the value of large projects such as storage that concentrate production on a single site and do not benefit from diversity across basins. Second, storage projects have a higher cost than ROR and PROR projects.

4.3 SG-1 Karnali river and basin conservation: Very low cost impacts of highly effective Karnali river conservation policies

We test eight scenarios for different Karnali basin conservation policies as part of this scenario group. The policies impose different constraints on the plants available to the model by removing certain hydropower plants from the portfolio available to SWITCH for development. Scenario K01 (Karnalli-all) is the most stringent, removing 189 projects (about 30%) from the portfolio. The remaining scenarios remove between 10 and 50 projects, or 2% to 8%. Consequently, cost results show that the Karnalli-all scenario has about 3.5% higher cost than the reference scenario. However, cost increase in all other conservation scenarios are lower than 1% compared to the reference scenario.

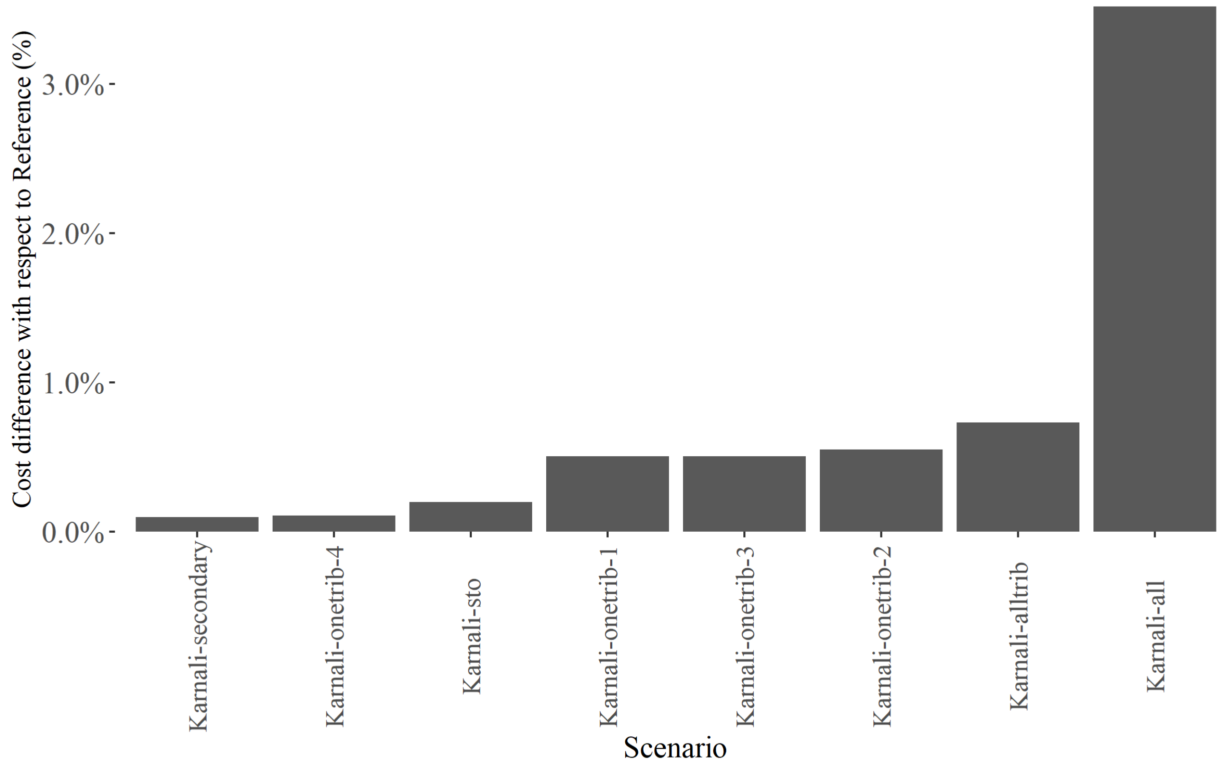

Figure 4.3.1 Cost difference between Karnali conservation scenarios and the reference scenario

Preventing or limiting deployment of hydropower in the Karnali basin has ripple effects across technologies and across the country. Figure 4.3.2 shows the energy mix for the Karnalli-all scenario, compared to the reference scenario. The unavailability of projects in the Karnali basin leads the model to develop storage and PROR hydropower mainly in the Gandaki (+100%) and Koshi (+60%) basins. The additional surplus coming from these projects lets the model slightly increase its use of imports compared to the reference scenario, but also drives higher wind adoption by the end of the simulation of up to 20% of annual energy needs compared to 5% in the reference scenario.

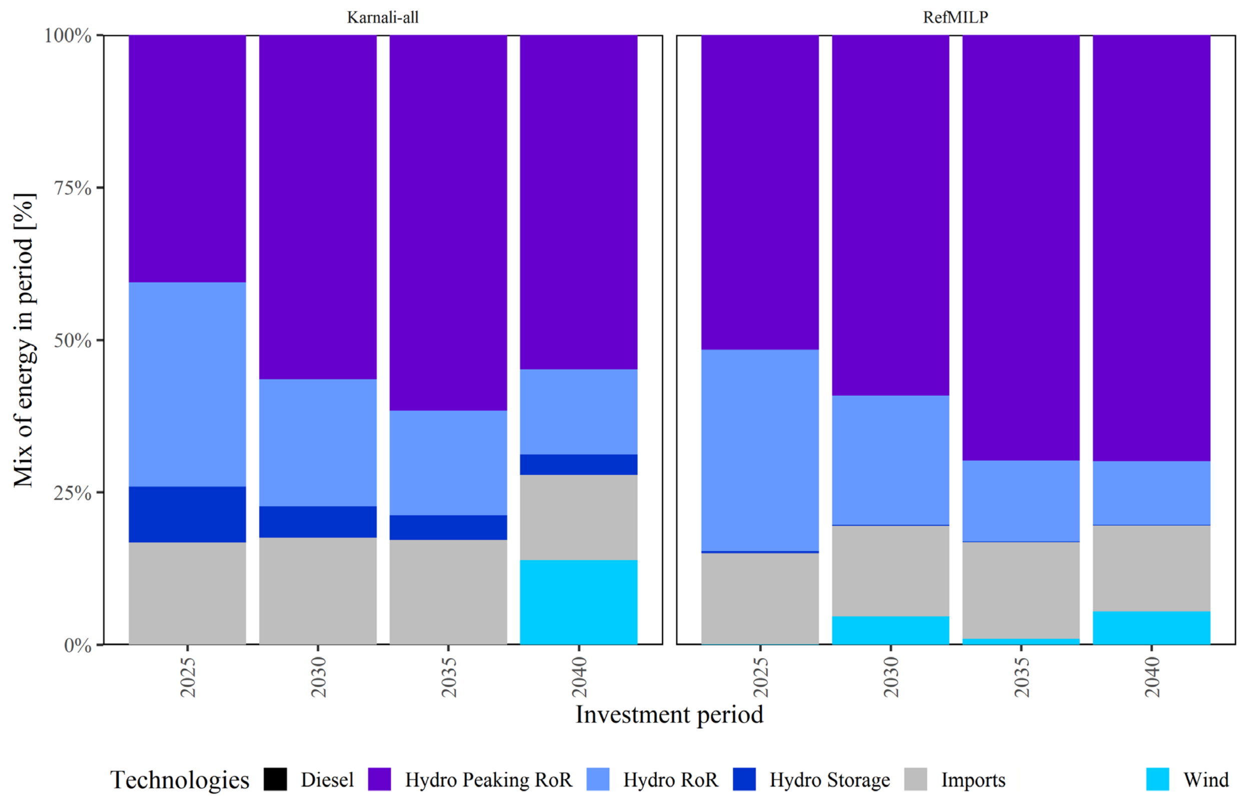

Figure 4.3.2 Energy mix for the reference scenario and the Karnalli-all scenario, by period

The remaining Karnali conservation scenarios do produce changes in the mix, even when their cost impact compared to the reference scenario is negligible (see Figure A.2.2. in Appendix). In all scenarios, wind adoption is displaced to 2040 due to choosing alternate hydropower projects in the same basin where the most cost effective wind projects would otherwise be developed. The additional transmission costs render these wind projects not cost effective to be developed before 2040. In most scenarios about 1 GW of ROR projects substitutes for PROR projects in the Karnali in the two last investment periods. These changes show that conservation policies in the Karnali basin will have ripple effects across the country, but also that proper planning of these policies and project choices leads to a cost-effective mitigation of those effects.

4.4 SG-2 Nepal river conservation: Nepal can conserve protected and HCV rivers at relatively low costs

We test eight hydropower constrained scenarios for the entire country, following a similar approach than for SG-1. Six scenarios represent actual conservation policy scenarios that Nepal could put in place to preserve rivers with certain properties. These scenarios include: protecting all FFR, preventing development in rivers with HCV below 1 and below 2, and not developing selected benchmark rivers and rivers in protected areas.

In addition to these conservation policy scenarios, we test two Nepal-wide limited hydropower growth scenarios. In one we limit hydropower development to capacity levels that equal a percentage of peak load on each period. In the second we test a moratorium of hydropower development in Nepal. The objective of these scenarios is to demonstrate that non-hydropower intensive pathways are feasible and to show how the system evolves with these limitations. These scenarios do not try to suggest Nepal should refrain from developing all of its hydropower resources, but to suggest that developing them, while cost-effective in many cases, is not the only pathway for power system growth.

Cost impacts of a Nepal-wide conservation scenario are 2% to 10% higher compared to the reference scenario. Hydropower-limited scenarios have much higher cost impacts of 20% to 34% (Figure 4.2.1). The lowest cost impact scenarios are the one that protects Nepal's benchmark rivers from being intervened (2.1% increase), and the one that prevents development in protected areas (1.5% increase).

Limiting hydropower development across Nepal with no clear conservation objectives may increase costs substantially more than a strategic approach. Three of the four hydropower limited scenarios have cost increases between 10% and 30%. The moratorium scenario has the highest cost increase at 34% compared to the reference scenario. A moratorium in hydropower development would increase average residential electricity bills by about $4.7 per household per month.

As would be expected, Nepal-wide scenarios have a higher impact on cost than a single basin constrained scenario as in SG-1. On the most stringent end, scenarios such as Nepal-FFR and Nepal HCV1 only allow 30%-40% of the projects in the portfolio to be developed. Less stringent scenarios such as Nepal-Protected and Nepal-Benchmark allow for 60% and 90% of projects to be developed. However, the number of projects available for development does not always correlate with cost impacts. The Nepal-Protected scenario has about a third less of the projects compared to the Nepal-Benchmark scenario, yet has lower cost impacts. This demonstrates that strategic selection of hydropower projects for conservation impacts coupled with cost assessment tools like the SWITCH model enhance decision making.

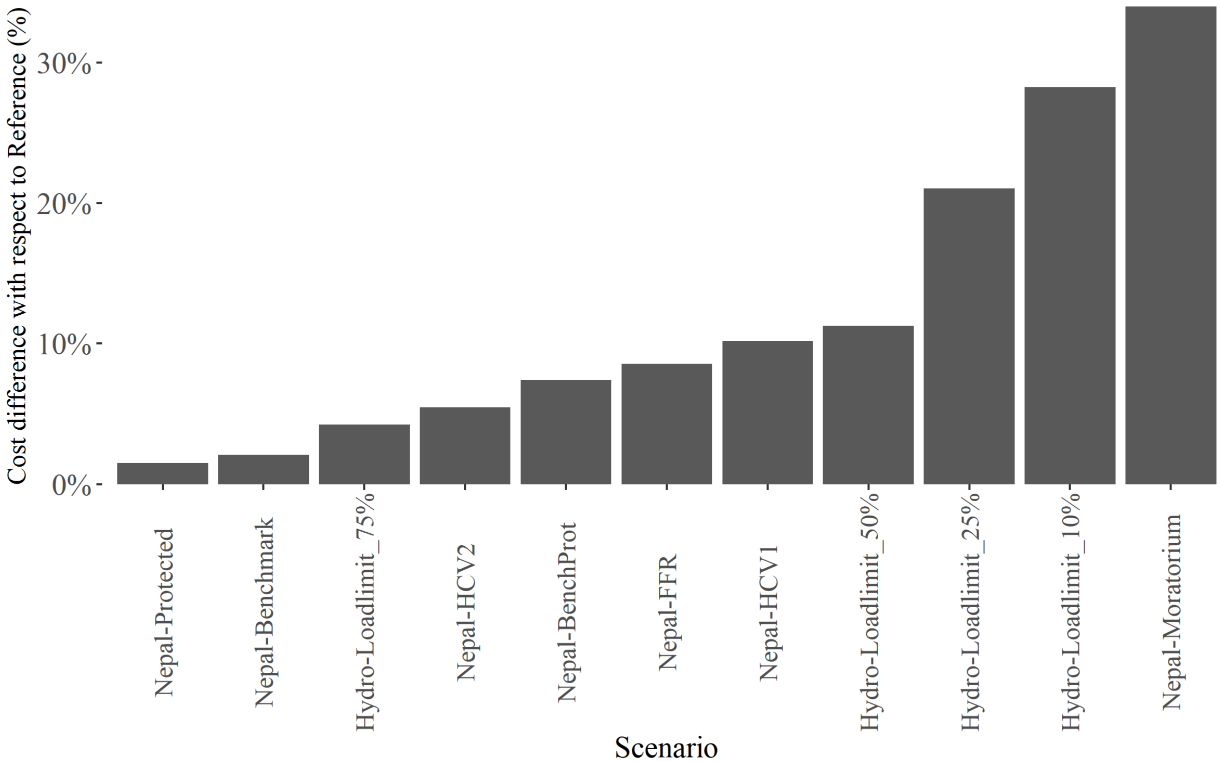

Figure 4.4.1 Cost difference between Nepal-wide conservation and hydropower constrained scenarios and the reference scenario

All conservation policy interventions produce a significant change in the resource mix (Figure 4.4.2). In some cases, like in the Nepal-HCV1, Nepal-Benchmark, and Nepal Protected scenarios, the conservation constraints trigger higher adoption of other renewable resources such as wind and solar. Indeed, up to 3.5 GW of additional wind and 1.4 GW of additional solar PV are deployed by 2040 in the Nepal-HCV1 scenario compared to the reference scenario. In other cases, the substitution takes place within hydropower technologies with an increase in storage hydropower like in the Nepal-FFR, Nepal-HCV2 and Nepal Benchmark/Protected combination scenarios. These different substitution pathways show the unintended consequences of certain conservation scenarios. For example, it is likely that scenarios that lead to higher adoption of storage hydropower will have higher ecosystem impacts than scenarios that lead to more adoption of wind and solar power.

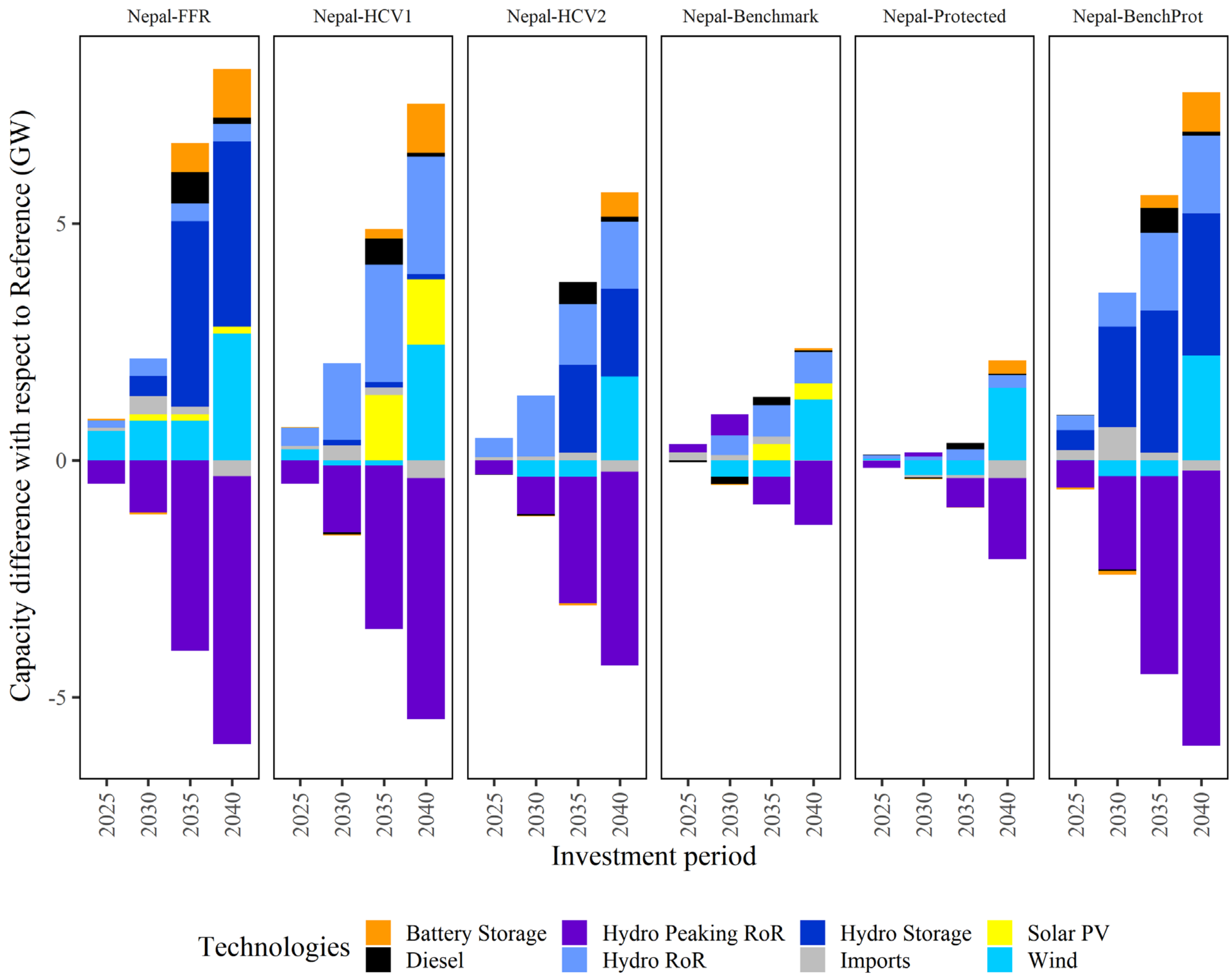

Figure 4.4.2 Capacity mix difference between Nepal-wide conservation policy scenarios and the reference scenario

The hydropower limited scenarios reflect what resource mix is possible with substantial limitations on development of this resource (Figure A.2.3 in Appendix). In the Nepal-Moratorium scenario over 1.8 GW of wind are developed as early as 2025, growing to 5.6 GW by 2040. Solar PV capacity is developed by 2035 at a full 10 GW, and triggers high adoption levels of battery storage up to 4.8 GW by 2040 (compared to about 0.3 GW in the reference scenario) to provide flexibility to solar resources. In 2035 and 2040 up to 75% of annual energy needs come from a combination of wind and solar power. The hourly dispatch for a resource mix based on renewable resources is also very different than a hydropower based case (Figure A.2.4 in Appendix). Exports and battery charging now take place throughout the year, during solar PV production hours, with batteries discharging in the evening peak hours after PV production has decreased. Batteries supply up to 50% of load in peak hours. Imports play a critical role in balancing solar power and also addressing seasonality of wind power.

More generally, substantial changes in resource mix do have impacts on import levels. The energy banking strategy is designed largely to fit a hydropower intensive power system that has a stark difference in production between dry and wet seasons. Scenarios that rely in large amounts of renewable resources do not exhibit the same marked seasonal behavior and then cannot procure the same level of imports as scenarios based on hydropower. Indeed, in the Nepal-Moratorium scenario, import levels drop from the 21%-25% range to the 15%-18% range, with a subsequent impact in costs (imports are predominantly cost-effective in this case study). In scenarios with hydropower limited by load levels, imports drop down to 13% in some periods. An energy banking strategy may not benefit Nepal if it chooses a less hydropower intensive path, and maintaining the reference level of imports closer to 25% - regardless of the levels of exports – could be economically efficient.

4.5 SG-4 Expansive hydropower: Relying solely on hydropower can be a costly strategy

The reference scenario, as well as most conservation policy scenarios in SG-1 and SG-2, rely substantially on hydropower and imports to meet Nepal's future electricity needs. However, about 5%-15% of energy comes from other resources, and a higher share of capacity is available from diesel peakers and storage for peaking and reserve purposes. We test a case where only hydropower development is allowed in Nepal, with wind, solar, diesel, and battery storage removed from the project portfolio. Imports still follow the energy banking logic.

Costs for this scenario are 10.7% higher than the reference scenario. On one hand, the lack of peaker dispatchable resources such as diesel and battery storage do require an overbuilding of supply especially to meet demand in the dry season. With an increase of surplus there is an increase of cost-effective import levels, which in this scenario go up to 28% in the first two periods and then down to 24% and 20% in 2035 and 2040, respectively. On the other hand, higher imports will mitigate some cost, and so will the potential revenue for the corresponding higher export levels that are not being accounted for (see Section 4.1). We explore the potential consequences of higher hydropower costs than anticipated in SG-9.

The expansive hydropower scenario reflects a common issue in systems with very high dependence on hydropower: excess capacity. Figure 4.6.1 shows installed hydropower capacity as a percent of peak demand on a given period for the reference scenario (right) and the current expansive hydropower scenario (left). The reference scenario deploys hydropower capacity at similar levels as peak demand. In contrast, a scenario that only expands based on hydropower requires up to 30%-70% more capacity to serve all demand reliably. This increase in demand is not related to energy needs: both the reference and expansive hydropower scenarios rely on hydropower to meet about 75% of energy consumption needs (see Figure A.2.5 in Appendix). The excess capacity is needed to meet peak demand in dry season, which require substantially higher capacity than in the reference scenario that can rely on diesel generation and battery storage discharge for these few peak hours. This excess hydropower capacity is then inefficiently used for most of the year, especially if exports do not materialize and leave domestic consumers to cover the additional costs.

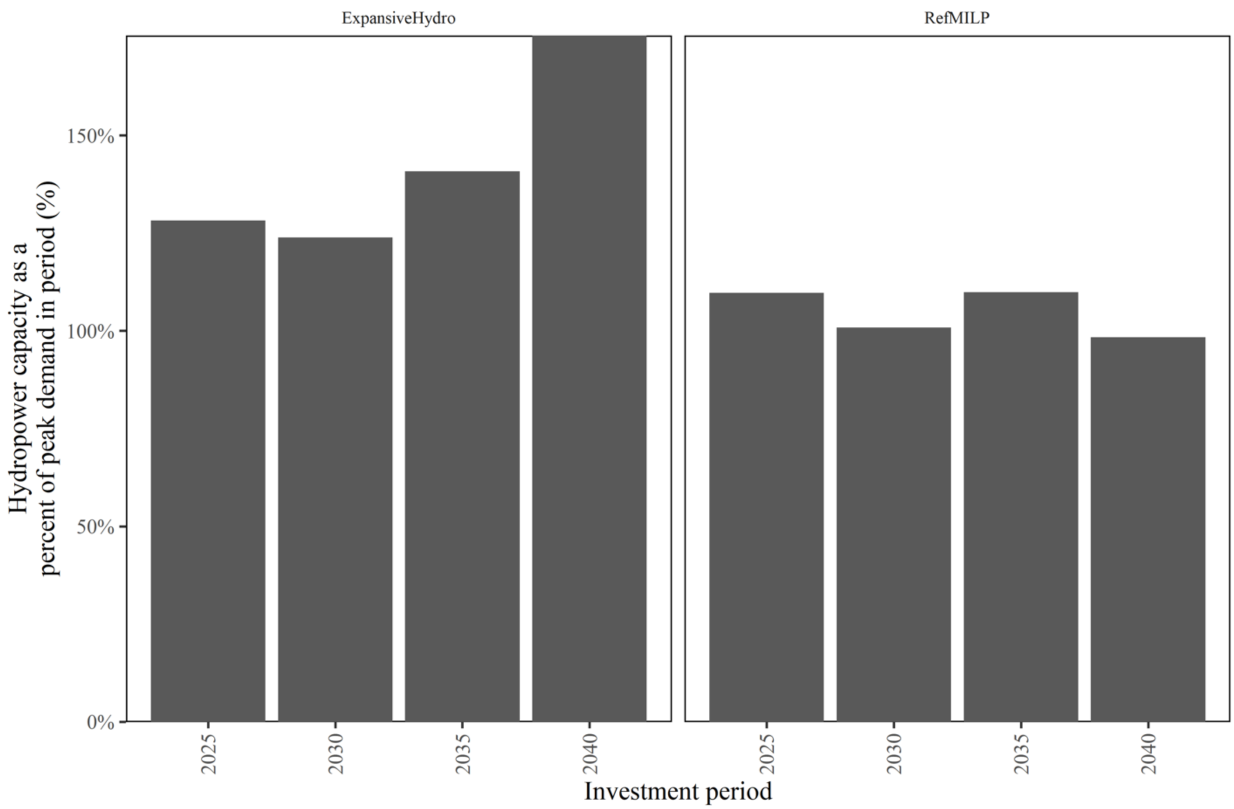

Figure 4.6.1 Hydropower capacity as a percent of peak load on each period

4.6 SG-5 Non-hydropower renewable portfolio standard (RPS)

Many countries have adopted renewable portfolio standards (RPS) to signal their willingness to increase renewable energy penetration in their power systems. These RPS policies require that certain levels of annual energy production come from eligible renewable resources such as wind, solar, hydropower, biomass, and others. While in many countries small hydropower are eligible resources to meet RPS targets, we only allow wind and solar to meet RPS targets in this study.

We test the impact of three levels of RPS policies in Nepal to further understand the way the system would evolve with higher level penetration of wind and solar PV. The three RPS policies are set to meet 20%, 35%, and 50% of energy needs by 2040, starting in 2025 with targets of 5%, 9%, and 13%, respectively. These scenarios complement the very high wind and solar PV penetration scenario that results from imposing a moratorium on hydropower development in Nepal (where 75% of energy was met with non-hydropower renewables by 2040).

Cost increases with respect to the reference scenario for the 20%, 35%, and 50% scenarios are 2.7%, 5.2% and 8.5%, respectively. We ran a sensitivity analysis for the 50% RPS scenario using less conservative solar PV costs based on expected costs for India and verified that the cost increase with respect to the reference scenario goes down to only 2.6%. This would indicate that with India-level costs for solar installations Nepal would be able to meet up to 35% of annual energy needs with wind and solar at similar costs as those of the reference scenario. The three RPS scenarios and the lower cost sensitivity case provide useful information on the relative value of wind and solar in Nepal. Solar is developed only as early as 2035 in all three scenarios (see Figure 4.7.1)[1]. RPS obligations in 2025 and 2030 are met solely with wind from a single project located in load zone 0, on the southwest of the country. In 2035, however, there is no wind development in any of the scenarios and the incremental RPS obligation is met solely with solar PV deployment. In 2040 wind deployment regains momentum[2].

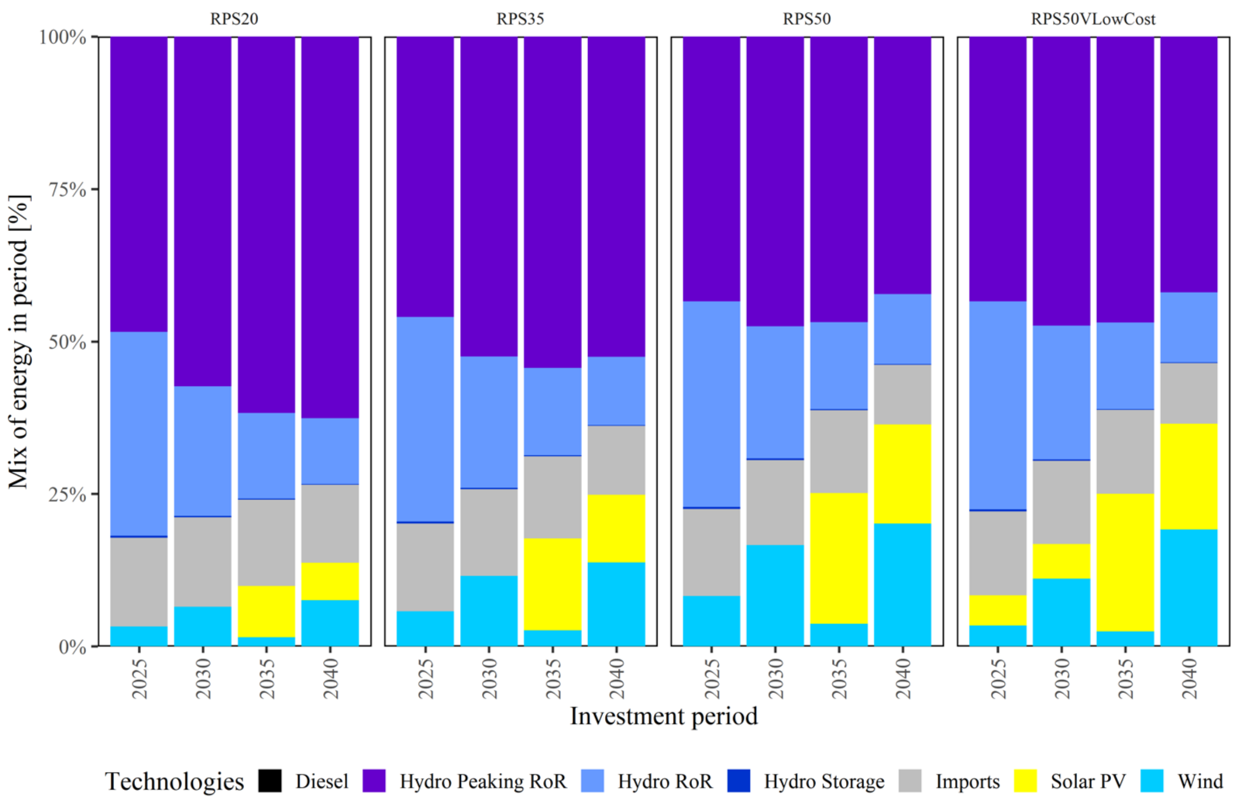

Figure 4.7.1 Energy mix for the three RPS scenarios and a sensitivity with low solar PV costs

The general trend for earlier wind adoption compared to solar may be related to the conservative values used for solar capital costs. Indeed, solar PV adoption patterns change substantially in the RPS50 low cost sensitivity scenario. Two thirds of the first period RPS target is met with solar PV, delaying wind development compared to the non-sensitivity scenario. However, in 2035 and 2040 wind and solar development are similar in both the conservative

[1] The reader may notice that the 2040 share of production mix from wind and solar is lower than the RPS target. This is because the chart includes production that is not meant for domestic use but for exports based on the energy banking strategy.
[2] This behavior is most likely explained by a sampling issue that results in unusually low wind production in the third simulation period. We decided to maintain the sampling pattern to better reflect the reality of planning for multi-year variation in wind production.

and the low PV cost scenarios, which suggests that the value of solar PV decreases relatively fast with its penetration.

The solar site most commonly developed across scenarios is in the district of Mustang, close to the China border. However, significant solar development takes place in the districts of Kathmandu and Bhaktapur that are much closer to load centers. Wind development is almost exclusively centered in the districts of Kapilvastu, Rupandehi, and Sunsari, all close to the Indian border.

4.7 SG-6 Import limits: Limiting imports from India can have substantial impact on power costs

The energy banking strategy designed and implemented in the reference scenario – and by extension in most scenarios in this case study – describes one of many possible future pathways for imports. There is political support in Nepal for a pathway that reduces or even eliminates dependence on imports. We test the impacts of such an approach by replacing the energy banking strategy with a prescribed annual allowance of imports as a share of total load. In this implementation we test three scenarios that allow 0%, 10%, or 25% of annual load to be met with imports in each simulation period.

If Nepal were to serve its demand for the next 20 years with no imports, system costs would be about 45% higher than the reference scenario, while an import limit at 10% of annual load has 17% higher costs than the reference scenario. These results suggest that imports, as calibrated in the model, play a very important role in securing affordability of wholesale and probably retail rates in the future Nepal system.

The reason why imports play such an important role on cost containment are easier to understand by inspecting the hourly dispatch in any period (see Figure 4.8.1 for an example for 2030 in the 0% imports sub-scenario). As in the expansive hydropower scenario, the system has to be overbuilt to have enough capacity to meet demand in the dry season that would otherwise be provided by imports (see Figure 4.2.2 for contrast). In addition, in the dry season diesel generation is dispatched throughout the day to meet demand and operating reserves, with the subsequent cost impacts.

The revenue from exporting surplus production from the wet season could mitigate some of the cost impacts of lacking imports, but a pure export strategy may be more difficult to negotiate than a strategy that relies on mutually beneficial exchanges with neighboring markets. In addition, in the absence of imports the system may be less resilient, more strained, and generally less flexible than in scenarios with imports allowed.

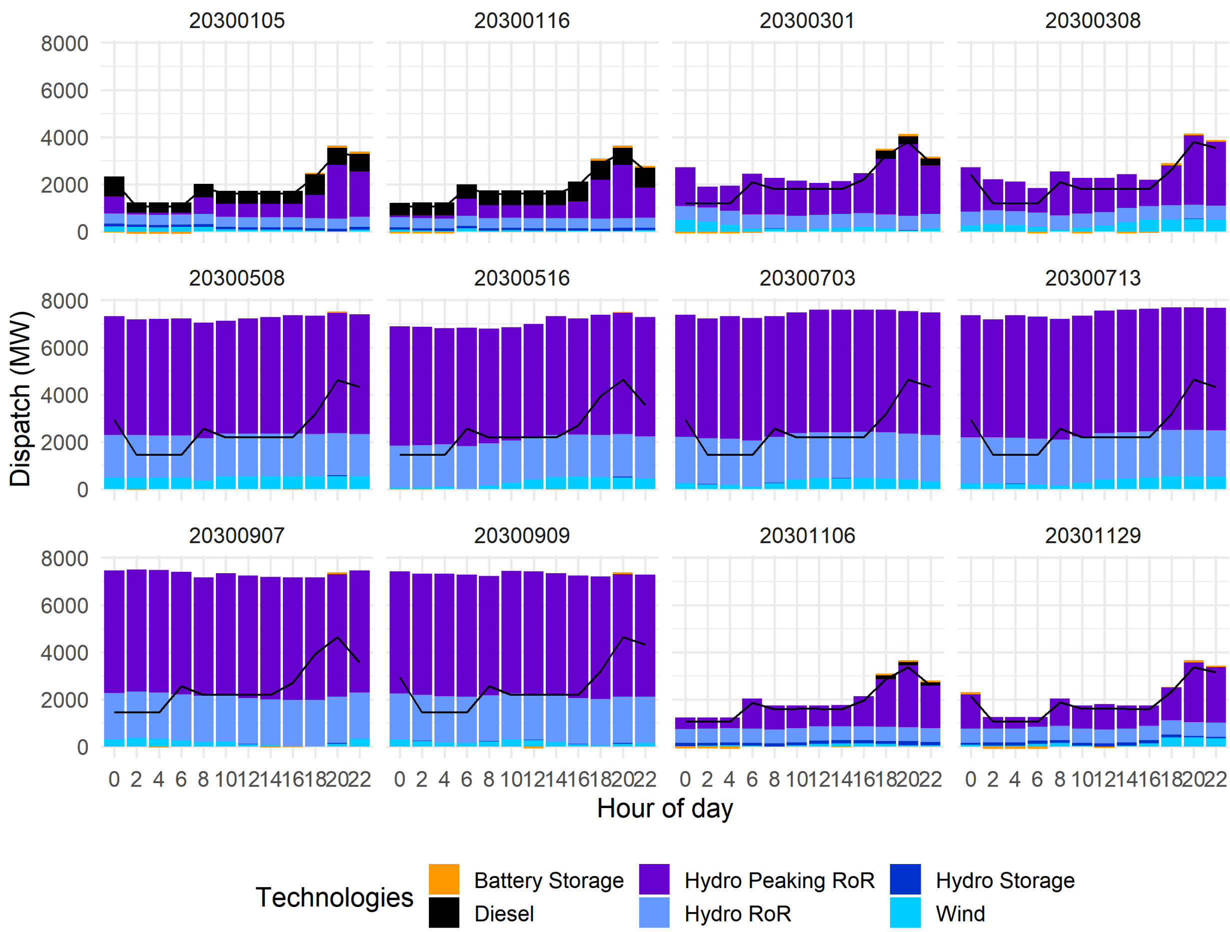

Figure 4.8.1 Hourly dispatch for each of the twelve days simulated for the 2030 period in the 0% imports scenario

Finally, the scenario that allows 25% imports has a lower cost than the reference scenario. This is because imports in the reference scenario are subject to the energy banking strategy that is forced to balance the benefits from increased imports with the cost increases of additional investment in capacity that produces energy surplus for export. As mentioned, this optimal cost balance yields a 21%-24% level of imports as a share of load. The 25% allowance is then more relaxed than the constraint implicit in the energy banking strategy, allowing more cost-effective imports and reducing costs by about 3%.

4.8 SG-7 Export strategy: Potentially profitable with the right prices and transmission costs

The export strategy scenario group focuses on the impact on the domestic generation mix that an increase in production would require to satisfy foreign loads. For simplicity, the implementation does not create a new load center outside of Nepal to isolate the impact in production from the impact on transmission for exports. We test two scenarios in this group, with net exports calibrated at 50% and 100% of domestic load, respectively. This means that the model will create power systems that produce a 50% and 100% net energy surplus compared to domestic load needs.

The capacity mix for the export strategy scenarios shows an increase of hydropower and a decrease of wind power and diesel peaking power compared to the reference scenario (Figure 4.9.1). The additional production comes mostly from additional PROR plants in the earlier periods, complemented with up to 3 GW of new storage hydropower in the 100% export scenario. The reduced amount of wind is probably due to the location of hydropower projects required for exports, which make the original selected wind project sites less desirable for development. The reduced need for diesel peakers probably comes from the new excess capacity available in the dry season due to the surplus export requirement.

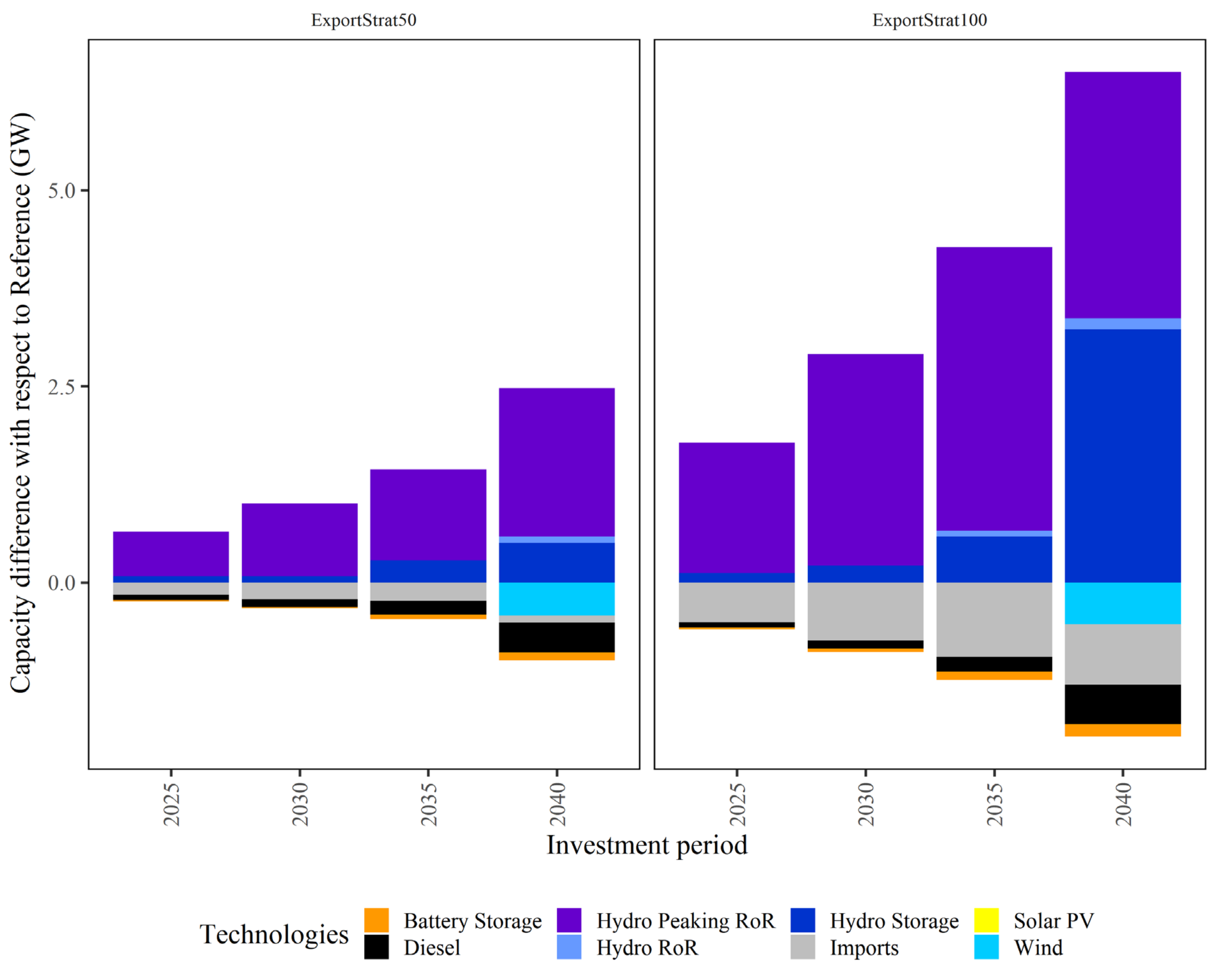

Figure 4.9.1 Capacity mix difference between export strategy scenarios and the reference scenario

As expected, costs are higher than the reference scenario given the expansion required. The 50% scenario costs are 7% higher than reference, while the 100% scenario costs are 21% higher than reference. The net costs depend on assumptions about revenue brought in from export sales. We make the assumption that 85% of the surplus is available for exports[3] and evaluate exports at 20 $/MWh, 30 $/MWh, and 40 $/MWh flat wholesale prices. For proper comparison against the reference scenario, we only monetize the portion of exports in excess of that resulting from the energy banking strategy implemented in the reference scenario (about 25% of load).

The analysis shows that at 20 $/MWh wholesale price neither scenario's revenue is enough to offset the additional capacity required to meet export requirements. The 50% and 100% export scenarios continue to have 2% and 7% higher cost than the reference scenario. At a 30 $/MWh wholesale price the 50% export scenario has slightly lower net costs, while the 100% export scenario slightly higher net costs. However, both are small enough to assume they are similar to the reference scenario. Finally, with a 40 $/MWh wholesale price the 50% and 100% scenario net costs are 3% and 6% lower than the reference scenario. These results suggest that an export strategy could be reasonable for Nepal if expected wholesale prices were above 30 $/MWh, approximately.

Note that the net cost calculation does not include the cost to expand the transmission system to mobilize the power out of the country. An inspection of hourly dispatch for 2040 in the 100% scenario suggests that up to 12 GW of transmission capacity would need to be available to export all surplus. From these 12 GW, 6.5 GW of net additional transmission capacity are needed assuming that the same lines used for imports are used for exports. We estimate that this additional 6.5 GW capacity could cost between $1.6 and $4.9 billion, potentially eroding much of the benefits from export revenue.

4.9 SG-8 The role of PROR and battery storage

PROR plants and battery storage can both provide intra-day load balancing service to the power system. In our model, PROR plants can store up to five hours of energy in their pondage storage and then release this power to meet load in peak hours subject to turbine capacity limitations. Battery storage is more flexible because it can charge from any available source of electricity and does not directly depend on resource seasonality like PROR does, but does fundamentally the same as the PROR by arbitraging intra-day costs and surplus.

In this scenario group we want to understand the relative importance of these two technologies to provide flexibility. The objective is to identify if battery storage could be a substitute for PROR in terms of flexibility, with potential conservation benefits of minimizing pondage area needs and flow alterations in run-of-river projects. As indicated in Section 3 and Table A.1.2, the PROR_NoBatt scenario removes battery storage from the portfolio in the reference scenario, but leaves PROR. In the PROR_Batt scenario, PROR plants are converted

[3] There are two reasons to justify this assumption. First, a portion of production "surplus" will come from deviation from expected production due to wetter than expected years and other operational variations. This portion is better understood as a "spill" that has no commercial value. Second, transmission constraints will most likely limit how much can be exported. Given the seasonality in Nepal's surplus, it is unlikely that the entire wet season surplus will be available for export on each hour, especially during low load hours in the nighttime.

to simple ROR plants with no storage capacity, and batteries are allowed. The latter scenario has the same potential annual energy production than the PROR_NoBatt scenario, but removes the ability of PROR plants to shift production during the day. Then, any change in the mix in these two scenarios will not be due to energy needs, but to flexibility needs. Note that we made no project cost adjustments when simulating PROR plants as ROR plants; it is possible that a ROR version of a PROR plant would be less expensive to build given reduced infrastructure needs.

Figure 4.10.1 shows the capacity mix for the two scenarios in this scenario group, and the corresponding reference scenario. In the absence of battery storage (scenario PROR_NoBatt), the model deploys up to 1.5 GW of additional storage hydropower by 2040 and about 50% more diesel capacity. This additional storage hydropower deployment substitutes for about 1 GW of PROR but does not affect ROR deployment. In contrast, in the absence of PROR plants (scenario PROR_Batt) the model develops almost 7 times more battery storage by 2040 (2 GW) and does not substitute PROR with storage hydropower. In the 2025-2035 period PROR capacity is substituted 1:1 with ROR capacity, but higher battery deployment in 2040 leads to reduced non-storage hydropower capacity compared to the reference scenario.

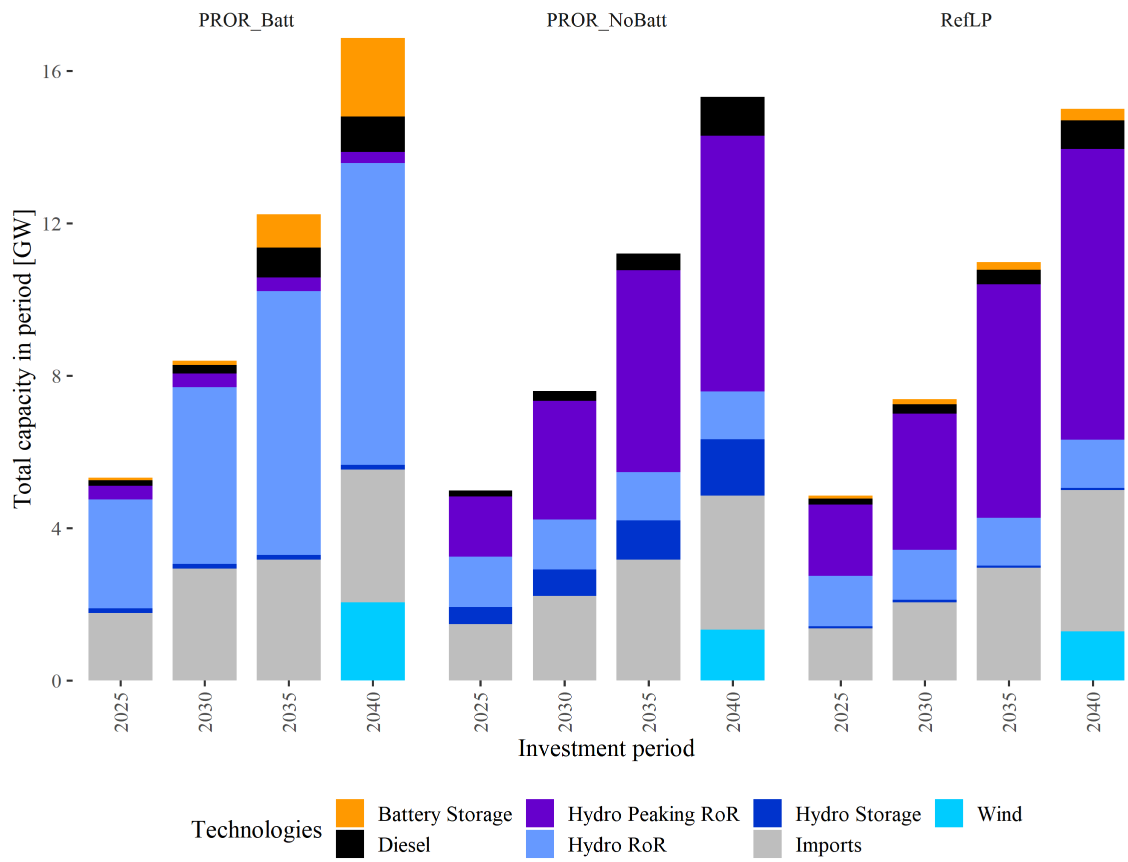

Figure 4.10.1 Capacity mix for reference, PROR_Batt and PROR_NoBatt scenarios

In terms of costs, the absence of PROR units has a higher cost impact than the absence of battery storage availability. Costs increase by 1.8% compared to the reference when batteries are not available, but increase by 4.4% compared to reference when PROR are simulated as ROR. A driver for the cost difference comes from the energy banking strategy. The absence of PROR units and higher battery deployment leads to lower surplus and hence lower cost-effective import levels, especially with higher battery uptake in 2035 and 2040. This suggests that, under an energy banking logic, higher battery storage deployment would reduce the needs for imports compared to higher deployment of PROR.

Cost differences suggest that battery storage can indeed substitute for PROR's flexibility capacity, but that its relative costs will still be higher until 2035-2040. In the PROR_NoBatt scenario, the model develops storage hydropower to replace the flexibility service provided by battery storage rather than deploying more PROR plants. This result shows that storage hydropower is a preferred substitute for battery storage compared to PROR plants due to their operational flexibility. It suggests that faster decrease of battery storage cost would lead to reduced hydropower storage and PROR deployment needs from an operational flexibility perspective.

4.10 SG-9 Higher hydropower costs: high impact on Nepal's power system costs

This scenario group examines the impact of higher-than-expected hydropower costs. One group of scenarios studies the investment decision impacts of higher hydropower costs when these higher costs are known to the model and hence decisions are made based on them. These can be understood as sensitivity scenarios. A second group of scenarios studies the cost impacts of higher hydropower costs when the investment decisions are sunk and there is no recourse. These scenarios are calculated by reevaluating the investments in hydropower from scenarios with the original cost levels using increased hydropower costs. As indicated before, we use a 25% and a 50% cost increase across all hydropower projects to simulate two possible cases. We apply these higher costs to the reference scenario (SG-0) and the expansive hydropower scenario group (SG-4)

As expected, overall system costs increase with higher hydropower costs. When investment decisions on hydropower are sunk, system costs increase 4% and 8% for the reference scenario with 25% and 50% increase in hydropower costs, respectively. In contrast, system costs increase 18% and 25% for the expansive hydropower scenario with 25% and 50% increase in hydropower costs, respectively. Note that since investment is sunk, there are no changes in the supply mix. These results suggest that high dependence on hydropower would make Nepal vulnerable to cost overruns from hydropower projects. Mitigation and hedging mechanisms could include detailed technical assessments, proper set up of tendering processes to prevent post-auction bid increases, and diversifying the generation portfolio with non-hydropower projects and imports based on long-term contracts.

When we allow the model to optimize subject to higher hydropower costs rather than assuming sunk costs, there are moderate levels of technology substitution. For the reference scenario (SG-0), a 25% cost increase case leads to substitution between wind and PROR only by 2040, with minimal changes in earlier periods. The 50% case also has very little change in mix in the three first periods, with 2 GW additional wind power by 2040 (two left panels in Figure 4.11.1). These results show that, under reference scenario assumptions, there are no significant hedging opportunities by substituting other technologies for high-cost hydropower in Nepal. However, under low renewable energy capital cost assumptions there is a more significant substitution between hydropower and solar PV technologies starting in 2030 for the 25% increase scenario and 2025 for the 50% increase scenario (two right panels in Figure 4.11.1). This demonstrates that under more favorable capital costs assumptions for wind, solar, and battery storage, these resources can offer some hedging against hydropower cost increases.

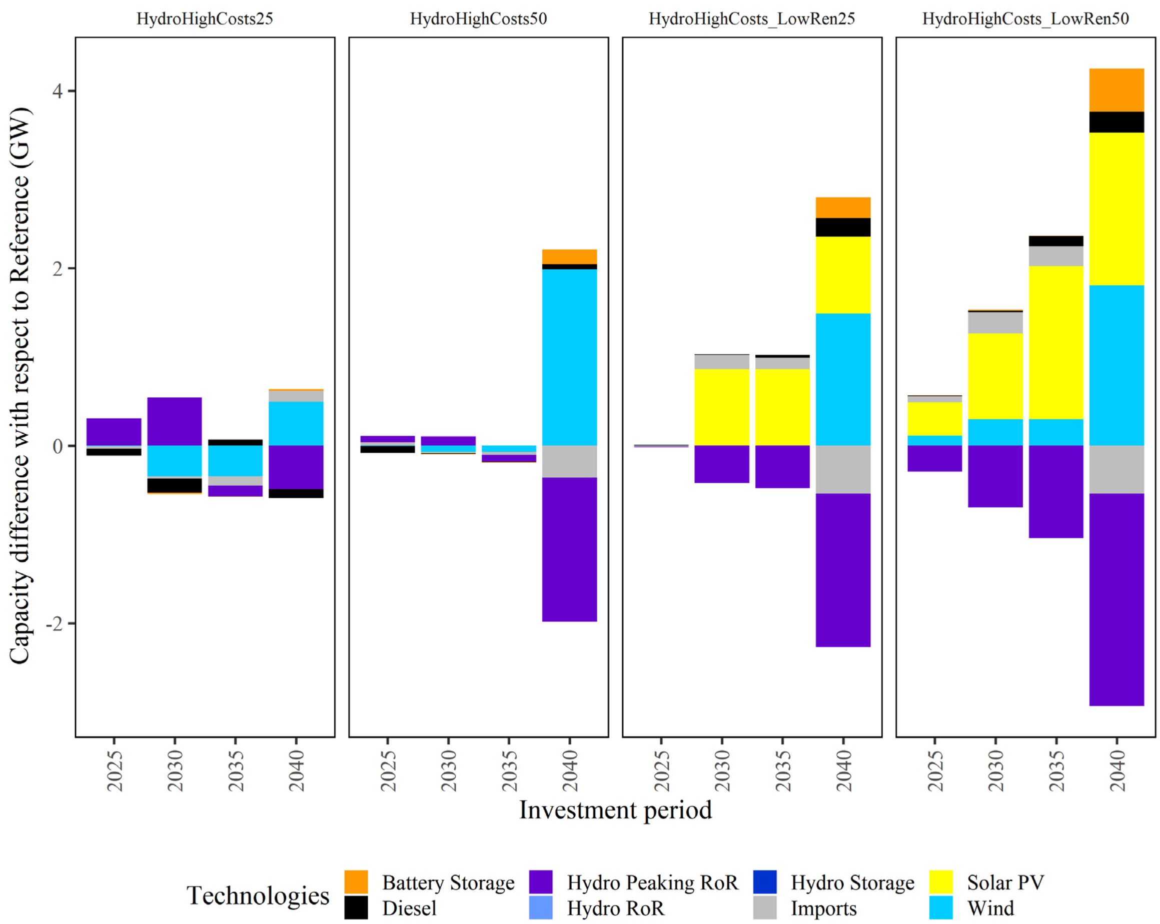

Figure 4.11.1 Capacity mix difference between high hydropower scenarios and the reference scenario, with and without lower renewable costs

For the expansive hydropower scenario (SG-4), higher hydropower costs have an impact on the levels of capacity procured (Figure 4.11.2). The optimization problem for the expansive hydropower costs – with no wind, solar, battery storage or diesel units available for deployment – translates to less procurement of storage hydropower and PROR and an increase in imports. Storage hydropower capacity decreases to half by 2040 in the both the 25% and

50% high cost scenarios. PROR deployment increases in the high cost scenarios to compensate for storage capacity loss, but also to allow higher import levels due to the logic of the energy banking strategy.

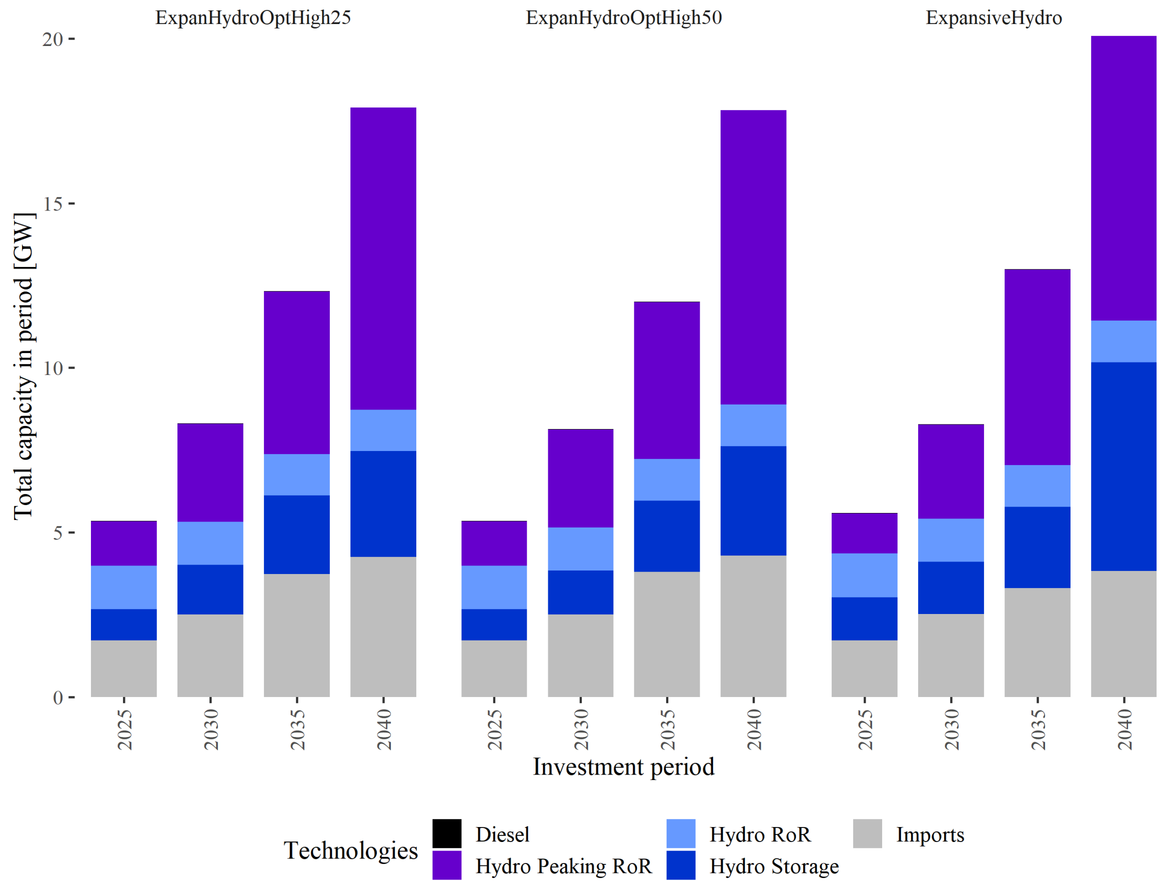

Figure 4.11.2 Capacity mix difference for expansive hydropower scenario with (two left) and without (right) high hydropower costs

It is important to note that the energy banking constraint prevents the model from resorting to increased imports to substitute for more expensive than anticipated hydropower. It is reasonable to believe that under economic import assumptions, the relative increase of hydropower costs compared to import costs would lead to increasing the volume of imports. This is supported by the model response to high hydropower costs in the expansive hydropower scenario by choosing hydropower plants that can create more surplus to increase imports.

Higher hydropower cost scenarios could also have other relevant impacts on an export strategy setting (SG-7). Hydropower projects meant for exports would probably negotiate their PPA prices with foreign buyers in the project financing stage, before siting and construction have begun. Cost overruns would significantly affect these projects, because they would not be able to pass those higher costs to the already signed PPAs and project profitability would be compromised. In contrast, hydropower projects meant for domestic consumption may be able to negotiate with the regulators passing all or some of the unexpected costs to rates.

4.11 SG-10 Regional equity strategy: potential social benefits with low cost

This scenario examines the impact of regional development strategies that require certain levels of investment across the country. As indicated, we run three scenarios that require load zone investment capacity equivalent to 10%, 20%, and 50% of peak demand in each load zone.
The regional allocation for generation capacity in the reference scenario is relatively uneven (Figure 4.12.1). About half of the load zones have generation capacity deployment levels above their local peak demand. Load zones 10 and 11 in the north central part of the country deploy several times their peak demand in hydropower capacity. Locally deployed generation in the remaining load zones has capacity levels less than 50% of their local peak demand in any period. There are five load zones – 1, 2, 3, 7, and 13 – that consistently deploy less than 25% of their peak demand in generation capacity. These correspond to centrally-located urban areas like Kathmandu and Bhaktapur or areas in the southeast with less cost-effective hydropower resources available.

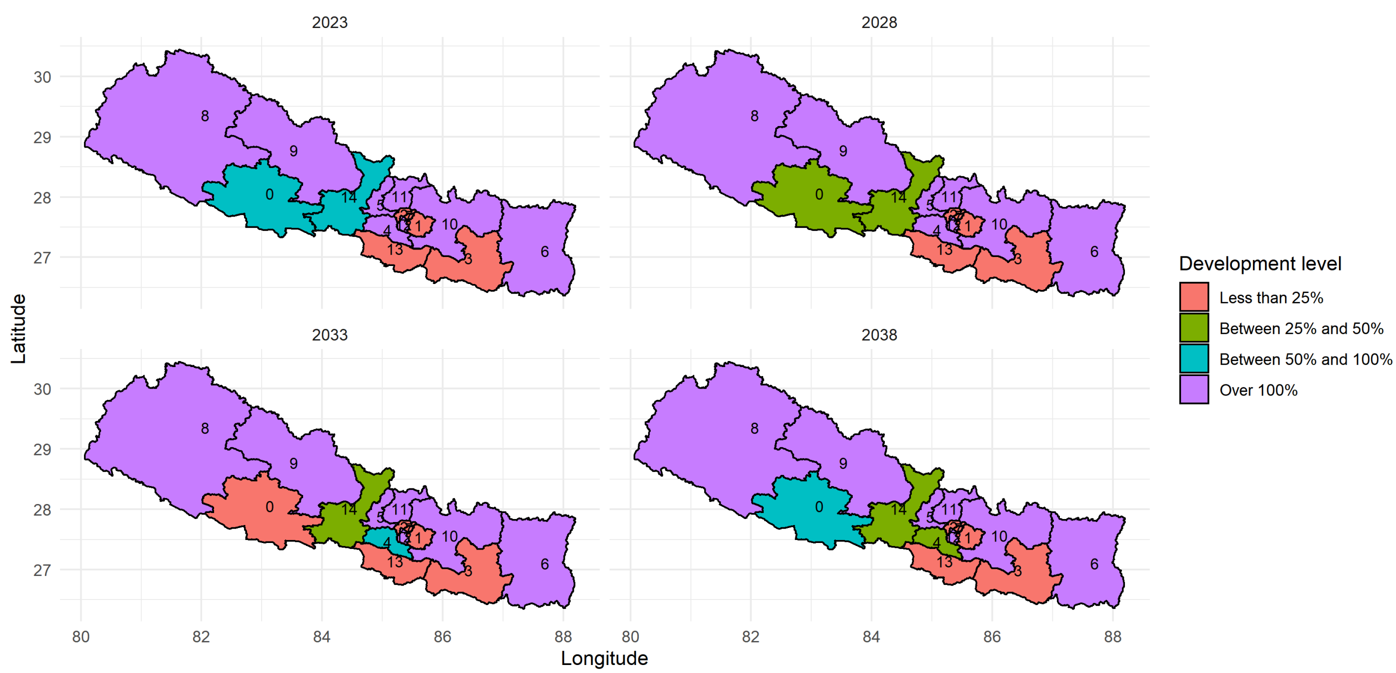

Figure 4.12.1 Load zone generation capacity investment measured in proportion to local peak demand on each period for reference scenario

Regional equity scenarios come with at least two tradeoffs. One is that as some regions increase their capacity, others must decrease deployment to avoid inefficient overbuilding. A second is cost: a system that requires certain levels of regional equity may need to avoid developing some cost-effective projects and will have a higher cost.

In the 50% scenario, less developed load zones such as 1, 2, 3, 7 and 13 increase local deployment to achieve capacity equal to 50% of their peak demand. At the same time, load zones such as 5, 8, 9, and 10 reduce their local generation capacity investment in various amounts (although still maintaining over double generation capacity compared to peak demand). The cost impact of the three regional equity deployment scenarios is relatively small. The 10% scenario turns out to be non-binding, as the reference scenario already satisfies that condition, and hence costs are the same. There is a 0.4% and a 2.4% increase in costs with respect to the reference scenario in the 20% and 50% scenarios, respectively. The cost increase from substitution of generation resources is balanced by transmission costs decreasing with increasing regional equity. For example, in the 50% scenario transmission costs are about 10% less than in the reference scenario. This result demonstrates that meeting higher shares of load with power from the same load zone requires less transmission capacity. If transmission costs were much higher than assumed in this case study, the advantages of regional equity policies on transmission cost savings could be significant.

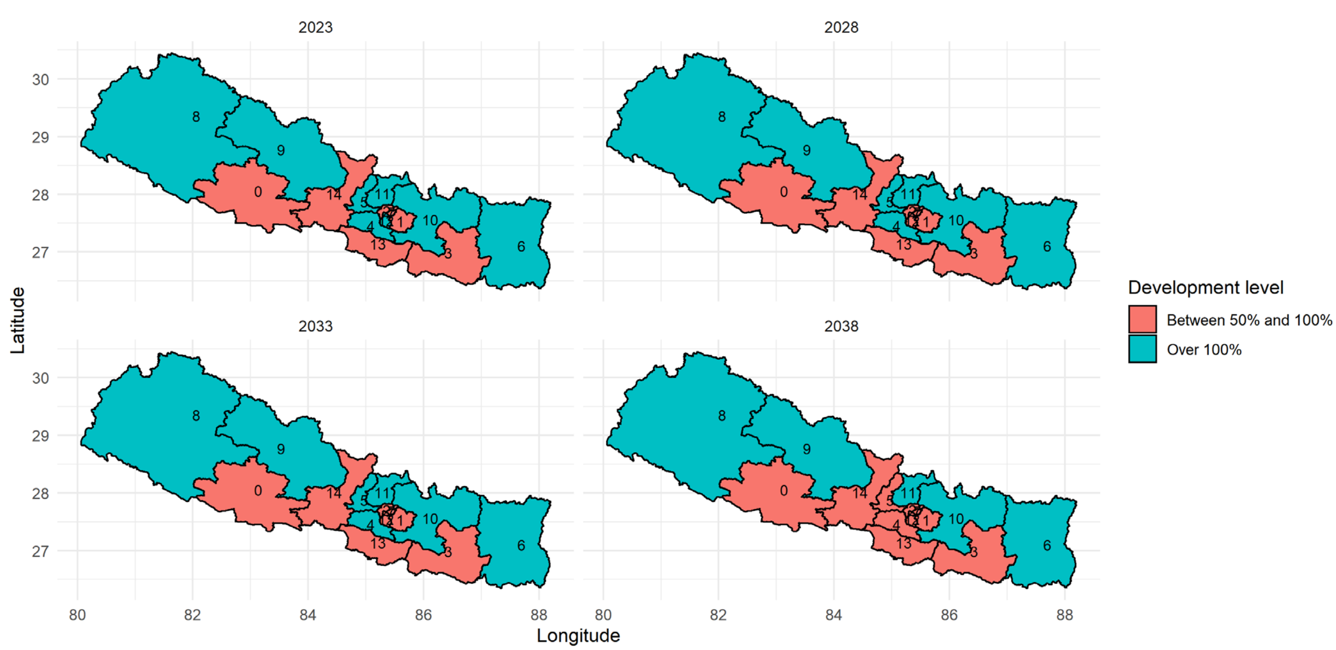

Figure 4.12.2 Load zone generation capacity investment measured in proportion to local peak demand on each period for the 50% equity scenario

A higher equity requirement drives changes in the resource mix (Figure 4.12.3). For example, PROR deployment is about 1 GW less by 2040 in the 50% scenario compared to the reference scenario. A diverse mix is deployed to substitute for this resource, including 0.5 GW of solar PV, about 1 GW of storage hydropower, and smaller incremental capacity levels of battery storage, diesel units, and ROR. The more diversified resource mix is the expected response to a regional equity requirement in a country where regional resource endowment is naturally uneven across the territory. In this case, load zones with high PROR potential postpone development to allow other resources to be employed in remaining regions.

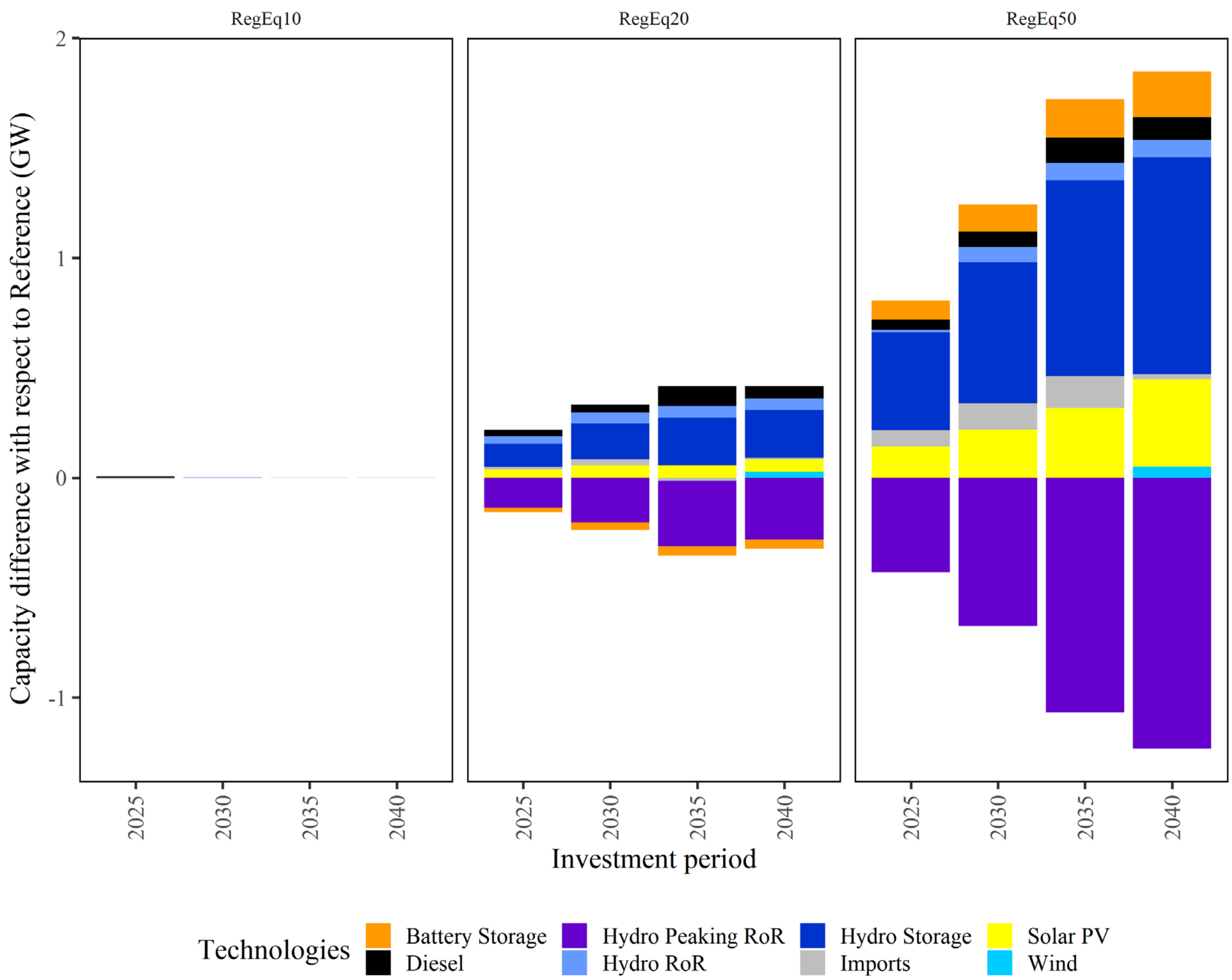

Figure 4.12.3 Capacity mix difference between regional equity policy scenarios and the reference scenario

5 Conclusion

Decisions about future hydropower development have to ensure that Nepal can meet its energy needs reliably, sustainably and affordably. One of the components of the Paani-WWF cooperation therefore evaluated the country's options for power generation. Nepal currently has an installed capacity of 1,303 MW, almost all (97%) of which is from hydropower, and an electricity deficit which is partly met through imports from India. Large future increases in power demand are projected.

Hydropower development has suffered from extensive delays, and generation is dependent on the seasonality and variability of rainfall. Meeting demand reliability during the dry season with a hydropower intensive system will produce large surplus during the wet season. Most hydropower installations are ROR plants, without storage capacity. Larger storage plants that require large capital investment have been left for the public sector, while independent power producers have focused on smaller and affordable ROR projects.

Other power technologies including wind, solar and batteries have become technically viable and cost-effective, and are growing at much faster rates than hydropower. They can be built faster and have lower risks of cost overruns, because they rely on standardized components. Their modularity allows to match uncertain demand growth much better than larger hydropower projects. These new technologies have lower impacts on the landscape and communities, and can provide more local economic development opportunities. However, because solar and wind production is more variable than hydropower on a short-term basis, they need to be combined with other technologies to balance power demand and supply. Nepal currently generates almost 2% of its total power supply from solar, and 0.12 % from wind. There is significant scope for growth of these renewables in the country.

Because today's investment decisions will determine the future mix of sources over decades, it is beneficial for countries to plan far ahead to ensure viable, least-cost and low-impact combinations of technologies over time. Once these combinations are identified, governments need to direct investments into the right direction. This can be done, for example, through the Nepal Electricity Agency's (NEA's) purchasing decisions (because NEA is Nepal's only buyer of power), or decisions on spatial planning and environmental licensing.

A number of power system expansion models are available to identify least-cost strategies to for power generation and transmission investment that meets future demand. We used the SWITCH model to find optimal investment portfolios, based on existing infrastructure, future costs and demand, hydrology, and available technologies (including all possible hydropower projects). The model simulates expansion of the power system in four stages (2025, 2030, 2035, and 2040). As a least-cost model, outputs from SWITCH always satisfy both the policy interest of keeping power costs low for consumers, and the private investor's interest in selecting competitive projects. Additional policy objectives (for example, reducing imports to regain energy independence, investing equally in the different regions of the country, or protecting certain rivers from hydropower development) can be introduced into the model. SWITCH will still select the least-cost option that meets these constraints.

The reference scenario expansion is mostly based on PROR plants and imports. About 75%-80% of the annual energy is produced from hydropower, with the remaining 20%-25% supplied by a mix of imports and wind energy. Wind is profitable from the first period, growing to almost 1 GW by 2040. The use of diesel plants is minimal but important, accruing less than 0.1% of energy in the year for their key use as peaker units in tight demand hours. Battery storage is deployed to provide alternative peak power starting in year 2025 with 80 MW, increasing to 300 MW by 2040.

The model results suggest that Nepal has options for considerable river conservation that will have minimal influence on power system cost. For example, building no projects in the Karnali basin, or building no projects on any free-flowing rivers in Nepal, would increase costs by only 2.5 and 9% respectively, because the country still has many of other potential projects including wind or solar and alternative strategically selected hydropower options available. Conservation scenarios produce a significant change in the resource mix. In some cases, the conservation constraints trigger higher adoption of other renewable resources such as wind and solar. This demonstrates that strategic selection of hydropower projects for conservation impacts coupled with cost assessment tools like the SWITCH model enhance decision making. The affordability of these scenarios would be further improved if lower costs for solar PV – such as those expected for India – would become available to Nepal.

SWITCH can be used to compare many other scenarios and their combinations, and to test specific portfolios of projects that look promising. Our results show that Nepal could greatly benefit from more strategic decisions in the power sector, rather than leaving investment decisions to private investors which simply do not have the information to select the projects that are in the country's best long-term interest. The technical report investigates the impacts of import curtailments, the cost and benefits of an export-oriented development strategy, the relative value of peaking RoR and batteries, and the impact of regional development policies, among others.

6 References

AEO, 2020. Capital Costs and Performance Characteristics for Utility Scale Power Generating Technologies (Annual Energy Outlook). Energy Information Administration (EIA).

Ansar, A., Flyvbjerg, B., Budzier, A., Lunn, D., 2014. Should we build more large dams? The actual costs of hydropower megaproject development. Energy Policy 69, 43–56. https://doi.org/10.1016/j.enpol.2013.10.069

BEA, 2017. Report on hydropower project cost overrun. Bhutan Electricity Authority, Bhutan.

Braeckman, J.P., Disselhoff, T., Kirchherr, J., 2019. Cost and schedule overruns in large hydropower dams: an assessment of projects completed since 2000. Int. J. Water Resour. Dev. 0, 1–16. https://doi.org/10.1080/07900627.2019.1568232

Carvallo, J.P., Ferrall, I., Kammen, D.M., 2018. Energy pathways for Uganda. An application of the SWITCH model. WWF.

Carvallo, J.P., Hidalgo-Gonzalez, P., Kammen, D.M., 2014. Envisioning a sustainable Chile: 5 findings about the future of the Chilean electricity and energy system. Natural Resources Defense Council, Berkeley, CA.

Carvallo, J.P., Shaw, B.J., Avila, N.I., Kammen, D.M., 2017. Sustainable low-carbon expansion for the power sector of an emerging economy: the case of Kenya. Environ. Sci. Technol. https://doi.org/10.1021/acs.est.7b00345

CEIC, 2015. Nepal | Average Monthly Household Income: Whole Kingdom | Economic Indicators [WWW Document]. URL https://www.ceicdata.com/en/nepal/household-

budget-survey-average-monthly-household-income/average-monthly-household-income-whole-kingdom (accessed 11.25.20).
Cole, W.J., Marcy, C., Krishnan, V.K., Margolis, R., 2016. Utility-scale lithium-ion storage cost projections for use in capacity expansion models, in: 2016 North American Power Symposium (NAPS). Presented at the 2016 North American Power Symposium (NAPS), pp. 1–6. https://doi.org/10.1109/NAPS.2016.7747866
He, G., Avrin, A.-P., Nelson, J.H., Johnston, J., Mileva, A., Tian, J., Kammen, D.M., 2016. SWITCH-China: A Systems Approach to Decarbonizing China's Power System. Environ. Sci. Technol. 50, 5467–5473. https://doi.org/10.1021/acs.est.6b01345
McBennett, B., Rose, A., Hurlbut, D.J., Palchak, J.D., Cochran, J.M., 2019. Cross-Border Energy Trade between Nepal and India: Assessment of Trading Opportunities (No. NREL/TP--6A20-72066, 1505936). https://doi.org/10.2172/1505936
NEA, 2019. NEA Annual Report 2018-2019 (Annual Report). Nepal Electricity Authority, Kathmandu, Nepal.
Nelson, J., Johnston, J., Mileva, A., Fripp, M., Hoffman, I., Petros-Good, A., Blanco, C., Kammen, D.M., 2012. High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures. Energy Policy 43, 436–447. https://doi.org/10.1016/j.enpol.2012.01.031
Ponce de Leon, D., Johnston, J., Moncada, M.V., Callaway, D., Kammen, D.M., 2015. Evidence and future scenarios of a low-carbon energy transition in Central America: a case study in Nicaragua. Environ. Res. Lett. 10, 104002. https://doi.org/10.1088/1748-9326/10/10/104002
Riahi, K., van Vuuren, D.P., Kriegler, E., Edmonds, J., O'Neill, B.C., Fujimori, S., Bauer, N., Calvin, K., Dellink, R., Fricko, O., Lutz, W., Popp, A., Cuaresma, J.C., Kc, S., Leimbach, M., Jiang, L., Kram, T., Rao, S., Emmerling, J., Ebi, K., Hasegawa, T., Havlik, P., Humpenöder, F., Da Silva, L.A., Smith, S., Stehfest, E., Bosetti, V., Eom, J., Gernaat, D., Masui, T., Rogelj, J., Strefler, J., Drouet, L., Krey, V., Luderer, G., Harmsen, M., Takahashi, K., Baumstark, L., Doelman, J.C., Kainuma, M., Klimont, Z., Marangoni, G., Lotze-Campen, H., Obersteiner, M., Tabeau, A., Tavoni, M., 2017. The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview. Glob. Environ. Change 42, 153–168. https://doi.org/10.1016/j.gloenvcha.2016.05.009
Rose, A., Chernyakhovskiy, I., Palchak, J., Koebrich, S., Joshi, M., 2020. Least-Cost Pathways for India's Electric Power Sector (No. NREL/TP-6A20-76153, 1659816, MainId:6155). https://doi.org/10.2172/1659816
Sanchez, D.L., Nelson, J.H., Johnston, J., Mileva, A., Kammen, D.M., 2015. Biomass enables the transition to a carbon-negative power system across western North America. Nat. Clim. Change 5, 230–234. https://doi.org/10.1038/nclimate2488
SARI/EI, 2017. Economic Benefits fromNepal-India Electricity Trade (No. IRADe-SARI/EI-2017-01). Integrated Research and Action for Development.
Timilsina, G.R., Toman, M., Karacsonyi, J., de Tena Diego, L., 2015. How Much Could South Asia Benefit from Regional Electricity Cooperation and Trade? (Policy Research Working Papers). The World Bank. https://doi.org/10.1596/1813-9450-7341
Appendix

6.1 Appendix A – SWITCH model description and scenarios

The objective function for SWITCH is to minimize total system costs, as indicated analytically in equation (S1).

$$System\ Cost = \ min\left\{\sum\nolimits_{p,u} \rho_{\rho} \cdot \left(k_u \cdot I^{G,T}_{p,u} + F^{G,T}_{p,u}\right) + \sum\nolimits_{h,u} \rho_{p(h)} \cdot \left(C^F_{h,u} + C^M_{h,u} + C^C_{h,u}\right) \cdot D^G_{h,u} \cdot \right.$$

$$\left. w_h + \sum\nolimits_{p,r}\left(k \cdot I^D_{p,r} + C^M_{p,r}\right)\right\} \tag{S1}$$

where $I^{G,T}{}_{p,u}$ are investment in generation G and transmission T in period p and for unit u; $F^{G,T}{}_{p,u}$ are their respective fixed costs; $C^F{}_{h,u}$ is fuel cost per operating hour h per unit u, $C^M{}_{h,u}$ are O&M costs, and $C^C{}_{h,u}$ are carbon costs, all multiplied by hourly dispatch $D^G{}_{h,u}$ and weighted by factor w_h; $I^D{}_{p,r}$ is investment in distribution in period p and load area r and $C^M{}_{p,r}$ its respective O&M costs. For efficient notation, a generation unit u is defined as a specific technology in a given location and a transmission unit u is an interconnection between two load areas. Investment costs are annualized through a capital recovery factor k_u and all costs are discounted to present using ρ_p. The discount rate is 7%.

The model enforces a set of constraints that make the simulation comply with basic power system restrictions, such as: maintain spinning and quickstart reserves, maintain minimum ecological flows from reservoirs, meet demand and supply at every single hour in the simulation, include the additional costs of ramping intermediate resources – usually natural gas plants – up and down to provide load following, respect transmission line capacity, and respect thermal, chemical, and mechanical storage stocks and capacity flows. Numerical values for operational constraints are included in Table A.1.1.

Constraint	**Value**	**Unit**	**Notes**
Planning reserve margin	15%	of annual peak load	Additional capacity required for resource adequacy
Load only spinning reserve requirement	3%	of load	Traditional spinning reserve requirement for load following only
Wind-specific spinning reserve requirement	5%	of installed wind capacity	Additional spinning reserve proportional to wind deployment
Solar-specific spinning reserve requirement	5%	of installed solar PV capacity	Additional spinning reserve proportional to solar PV deployment
Spinning reserve ramping constraints: CCGT	25%	of installed capacity	Maximum available capacity to provide spinning reserve on a given unit. Corresponds to the 10-minute ramp rate
Spinning reserve ramping constraints: SCCT and engines	30%	of installed capacity	Maximum available capacity to provide spinning reserve on a given unit. Corresponds to the 10-minute ramp rate
Minimum storage requirement for spinning reserve	1	hour	Minimum hours of storage that need to be available for a given storage unit to provide spinning reserve
Heat rate spinning reserve penalty: CCGT	30%	of nominal heat rate	Additional heat rate penalty incurred by units of this type of technology when providing spinning reserve.
Heat rate spinning reserve penalty: SCCT ane engines	9%	of nominal heat rate	Additional heat rate penalty incurred by units of this type of technology when providing spinning reserve.
Quickstart reserve	3%	of load	Additional capacity required as operation reserve
Ramp up costs: CCGT	9.16	MMBTu/MW	Additional fuel cost for ramping a CCGT
Ramp up costs: SCCT and engines	0.22	MMBTu/MW	Additional fuel cost for ramping a gas or diesel turbine/engine
Minimum loading for baseload	100%	of installed capacity	Applies to geothermal, CCS, co-generation, and nuclear plants (if they exist)
Minimum loading for flexible baseload	40%	of installed capacity	Applies to coal steam turbines

Minimum flow for reservoir hydropower	25%	of available reservoir hydro capacity	Minimum dispatch requirement for reservoir hydro to mimic minimum downstream flow requirements
Hydropower operating reserve limit	20%	of available reservoir hydro capacity	Limits to 20% how much hydropower capacity is available to be used as spinning reserve.
Storage discharge rate	100%	of installed capacity	How much of the installed capacity can be discharged on a given hour. Set at the same value as the installed capacity
Storage roundtrip efficiency	85%	of stored energy	Percentage of energy that is not available after being stored.

Table A.1.1 Numerical values for SWITCH-Nepal operational parameters.

Table A.1.2 describes all the scenarios developed for this study

Scenario ID	Modifier	Scenario Group	SSP Scenario ID	Scenario name	Short name	Description	Model Type
4009	0	SG0	N/A	Reference LP	RefLP	Reference scenario	LP
4010	0	SG0	N/A	Reference MILP	RefMILP	Reference scenario	MILP
4011	0	SG1	K01	Karnali No Hydro	Karnali-all	No new hydro in Karnali basin	MILP
4012	0	SG1	K02	Karnali No Storage Hydro	Karnali-sto	No new storage hydro in Karnali basin	MILP
4013	0	SG1	K03	Karnali-secondary	Karnali-secondary	No mainstem dams - only development in secondary river systems in Karnali basin	MILP
4014	0	SG1	K04	Karnali-alltrib	Karnali-alltrib	No mainstem dams and no additional dams in all four tributaries of the Karnali	MILP
4015	0	SG1	K05	Karnali FFR Tributary 1	Karnali-onetrib-1	No mainstem dams and at least one tributary of the Karnali free flowing (1)	MILP
4016	0	SG1	K06	Karnali FFR Tributary 2	Karnali-onetrib-2	No mainstem dams and at least one tributary of the Karnali free flowing (2)	MILP
4017	0	SG1	K07	Karnali FFR Tributary 3	Karnali-onetrib-3	No mainstem dams and at least one tributary of the Karnali free flowing (3)	MILP
4018	0	SG1	K08	Karnali FFR Tributary 4	Karnali-onetrib-4	No mainstem dams and at least one tributary of the Karnali free flowing (4)	MILP

Scenario ID	Modifier	Scenario Group	SSP Scenario ID	Scenario name	Short name	Description	Model Type
4020	0	SG2	N01	Nepal-FFR	Nepal-FFR	No development in rivers that are classified as free-flowing as a result of free-flowing river analysis. Dam development on stretches with “good connectivity” is still possible	MILP
4021	0	SG2	N02	Nepal-HCV1	Nepal-HCV1	Projects can only be developed in rivers that have an aggregated HCV value below or equal to 1. However, in this scenario, dams could be developed on rivers that are free-flowing.	MILP
4022	0	SG2	N03	Nepal-HCV2	Nepal-HCV2	Projects can only be developed in rivers that have an aggregated HCV value below or equal to 2.	MILP
4023	0	SG2	N04	Nepal-Benchmark	Nepal-Benchmark	“Benchmark/candidate” rivers are rivers which match the definition of HCVR according to the experts (Karnali, Humla Karnali, Budhi Gandaki, West Seti and Tamor). Some other rivers have been added in this scenario based on the importance of those river for biodiversity (Tila, Bheri, East Rapti, Thuligad, Babai, Thulo Bheri)	MILP
4024	0	SG2	N05	Nepal-Protected	Nepal-Protected	Hydropower producers should leave 50% of mean monthly flow if structures built within PAs. So, less HP production in these rivers, and more impact on biodiversity dependent on these rivers. Also includes boundary rivers of PAs, which need conservation in the opposite bank of PAs.	MILP
4025	0	SG2	N06	Nepal-Benchmark and Protected	Nepal-BenchProt	3023 and 3024 together	MILP
4026	0	SG2	N/A	Nepal-Moratorium	Nepal-Moratorium	No hydropower allowed. May not converge	LP

Scenario ID	Modifier	Scenario Group	SSP Scenario ID	Scenario name	Short name	Description	Model Type
4027	0.1	SG2	N/A	Nepal-Hydro Limited to Share of Peak Load	Hydro-Loadlimit_10%	Limit national hydropower development to 10% of peak load on each period	LP
4027	0.25	SG2	N/A	Nepal-Hydro Limited to Share of Peak Load	Hydro-Loadlimit_25%	Limit national hydropower development to 25% of peak load on each period	LP
4027	0.5	SG2	N/A	Nepal-Hydro Limited to Share of Peak Load	Hydro-Loadlimit_50%	Limit national hydropower development to 50% of peak load on each period	LP
4027	0.75	SG2	N/A	Nepal-Hydro Limited to Share of Peak Load	Hydro-Loadlimit_75%	Limit national hydropower development to 75% of peak load on each period	LP
4028	0	SG4	N/A	Expansive Hydropower	ExpansiveHydro	Only hydropower allowed in the portfolio. Remove all other technologies. Allow imports based on reference case definitions	LP
4032	0	SG4	N/A	Expansive Hydropower	ExpansiveHydro	Only hydropower allowed in the portfolio. Remove all other technologies. Allow imports based on reference case definitions	MILP
4029	0.2	SG5	N/A	NonHydro RPS 20%	RPS20	Implement a renewable portfolio standard that requires 20% of energy to come from non-hydro renewable resources	LP
4029	0.35	SG5	N/A	NonHydro RPS 35%	RPS35	Implement a renewable portfolio standard that requires 35% of energy to come from non-hydro renewable resources	LP
4029	0.5	SG5	N/A	NonHydro RPS 50%	RPS50	Implement a renewable portfolio standard that requires 50% of energy to come from non-hydro renewable resources	LP
4030	0.5	SG5	N/A	NonHydro RPS 50% with low solar/wind/battery cost	RPS50LowCost	Implement a renewable portfolio standard that requires 50% of energy to come from non-hydro renewable resources. Uses optimistic/low investment costs for wind, solar, and storage	LP
3046	0.5	SG5	N/A	NonHydro RPS 50% with very low solar/wind/battery cost	RPS50VLowCost	RPS 50% using the lowest PV costs available from the India paper	LP

Scenario ID	Modifier	Scenario Group	SSP Scenario ID	Scenario name	Short name	Description	Model Type
3031	0	SG6	N/A	Import limit at 0% energy consumption	ImportLim0	No imports are allowed. The energy banking constraint is disabled and a constraint to prevent imports is implemented.	LP
3031	0.1	SG6	N/A	Import limit at 10% energy consumption	ImportLim10	Imports are limited to 10% of total period-level energy consumption. The energy banking constraint is disabled and a constraint to prevent imports is implemented.	LP
3031	0.25	SG6	N/A	Import limit at 25% energy consumption	ImportLim25	Imports are limited to 25% of total period-level energy consumption. The energy banking constraint is disabled and a constraint to prevent imports is implemented.	LP
3034	0.5	SG7	N/A	Export strategy	ExportStrat50	The model energy balance constraint is modified to require 50% surplus compared to imports, and 100% surplus compared to imports	LP
3034	1	SG7	N/A	Export strategy	ExportStrat100	The model energy balance constraint is modified to require 50% surplus compared to imports, and 100% surplus compared to imports	LP
4036	0	SG8	N/A	PROR and batteries 1	PROR_NoBatt	Battery storage is removed from the portfolio of new projects	LP
4037	0	SG8	N/A	PROR and batteries 2	PROR_Batt	PROR plants are declared as ROR plants, effectively removing their intra-day storage capability	LP
4038	0.25	SG9	N/A	Expensive Hydro	HydroHighCosts25	Higher hydropower costs, 25% above the original reference value	MILP
4038	0.5	SG9	N/A	Expensive Hydro	HydroHighCosts50	Higher hydropower costs, 50% above the original reference value	MILP
3042	0	SG9	N/A	Reference MILP HighHydro25	RefMILP Hyd25	Forcing higher hydro costs over 4010 scenario, 25% increase	MILP
3043	0	SG9	N/A	Reference MILP HighHydro50	RefMILP Hyd50	Forcing higher hydro costs over 4010 scenario, 50% increase	MILP

Scenario ID	Modifier	Scenario Group	SSP Scenario ID	Scenario name	Short name	Description	Model Type
3044	0	SG9	N/A	Expansive HighHyd25	ExpanHydroHigh25	Forcing higher hydro costs over 4032 scenario, 25% increase	MILP
3045	0	SG9	N/A	Expansive HighHyd50	ExpanHydroHigh50	Forcing higher hydro costs over 4032 scenario, 50% increase	MILP
3047	0.25	SG9	N/A		ExpanHydroOptHigh25	Expansive hydro (4032) with higher hydropower costs, 25% incr	MILP
3047	0.5	SG9	N/A		ExpanHydroOptHigh50	Expansive hydro (4032) with higher hydropower costs, 50% incr	MILP
3039	0.1	SG10	N/A	RegionalEquity 10%	RegEq10	Minimum installed capacity at the LZ level of 10% of domestic peak load for each period	LP
3039	0.2	SG10	N/A	RegionalEquity 20%	RegEq20	Minimum installed capacity at the LZ level of 20% of domestic peak load for each period	LP
3039	0.5	SG10	N/A	RegionalEquity 50%	RegEq50	Minimum installed capacity at the LZ level of 50% of domestic peak load for each period	LP
3040	0.25	Futures	N/A	ExpHydro_LowRen25	HydroHighCosts_LowRen25	Joint effects of higher hydro costs and lower renewable costs, based on the reference scenario	LP
3040	0.5	Futures	N/A	ExpHydro_LowRen50	HydroHighCosts_LowRen50	Joint effects of higher hydro costs and lower renewable costs, based on the reference scenario	LP
3041	0	Futures	N/A	NepalFFR_LowRen	NepalFFR_LowRen	Scenario 4020 (Nepal FFR) with very low renewables and battery cost. I brought down the battery cost just guessing, need to support it	MILP

Table A.1.2 Detailed list of scenarios developed for this study.

6.2 Appendix B – Additional result figures

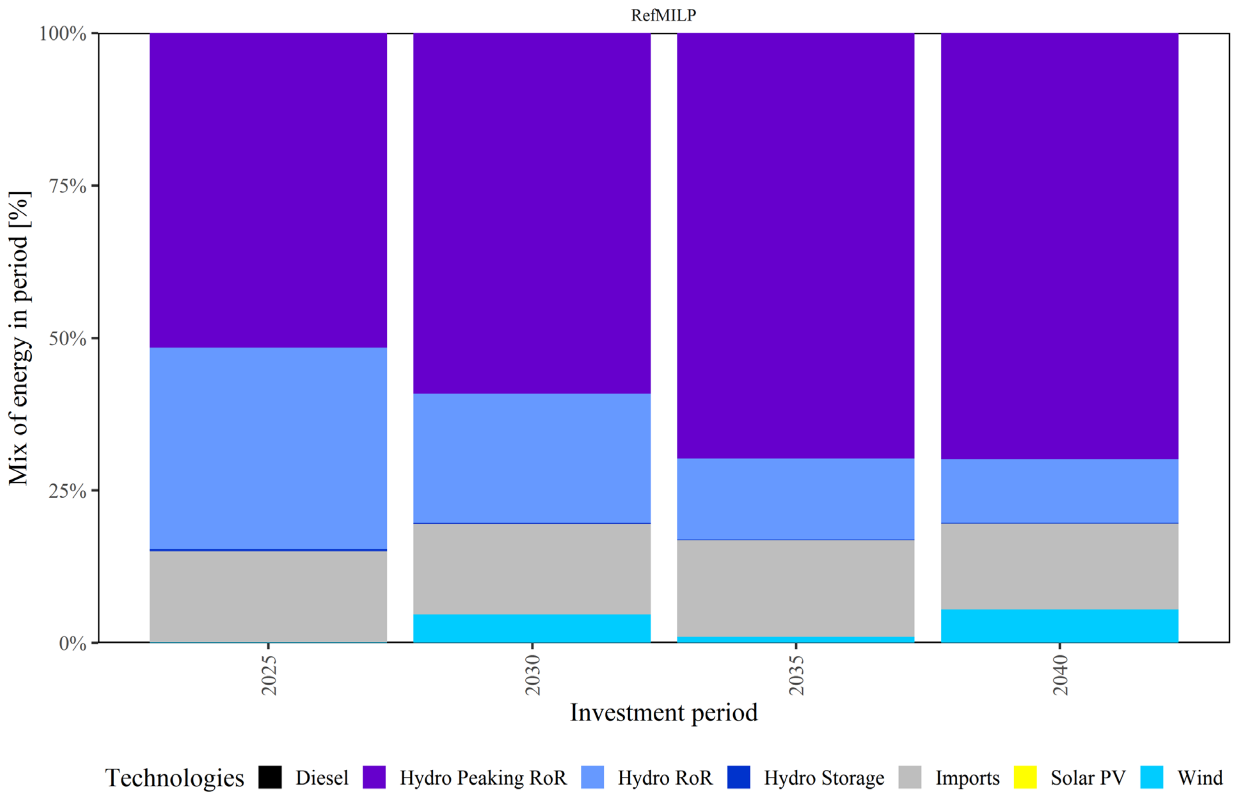

Figure A.2.1 Energy mix by period and technology for the MILP reference scenario.

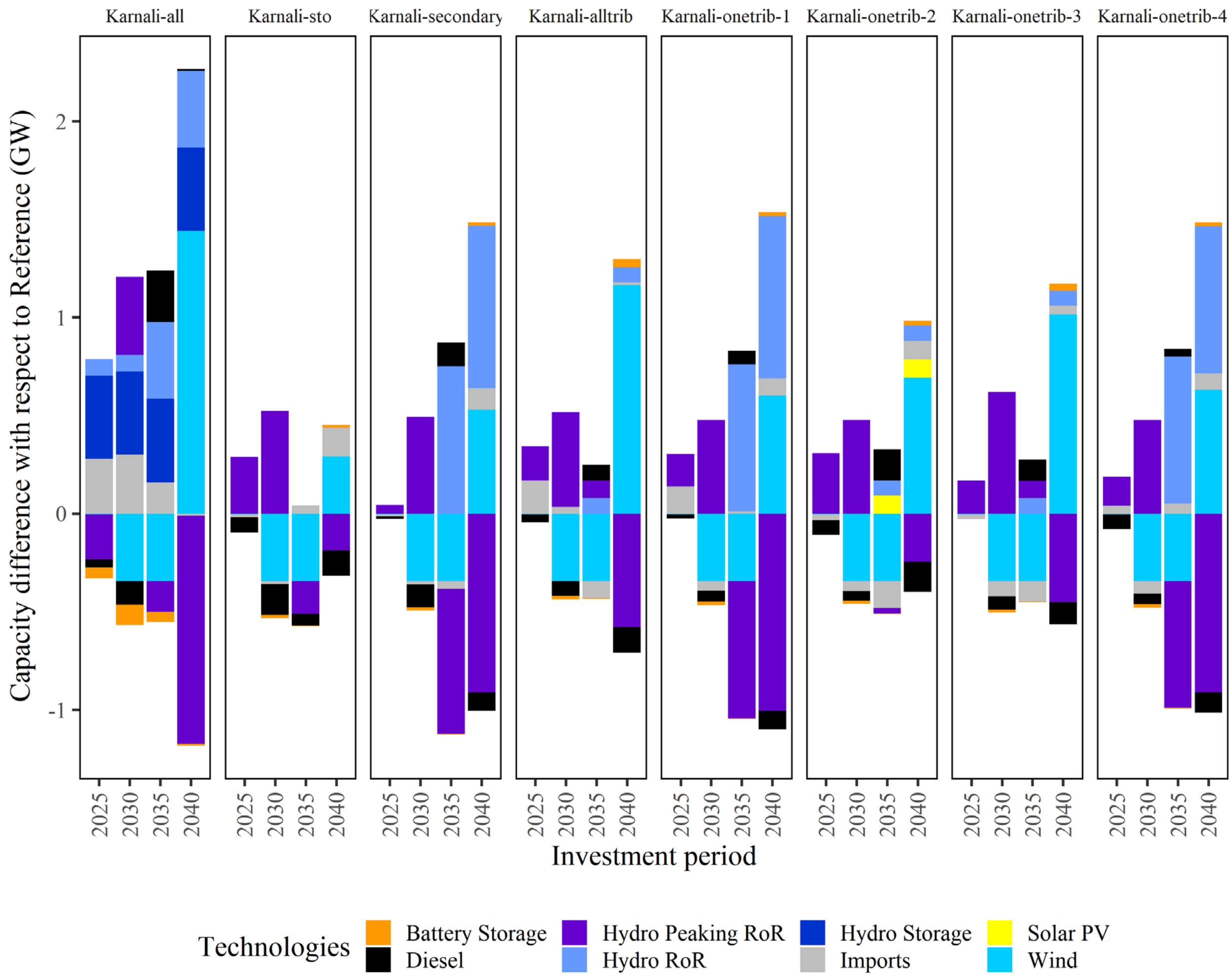

Figure A.2.2 Capacity mix differential between reference scenario and Karnali conservation scenarios in SG-1

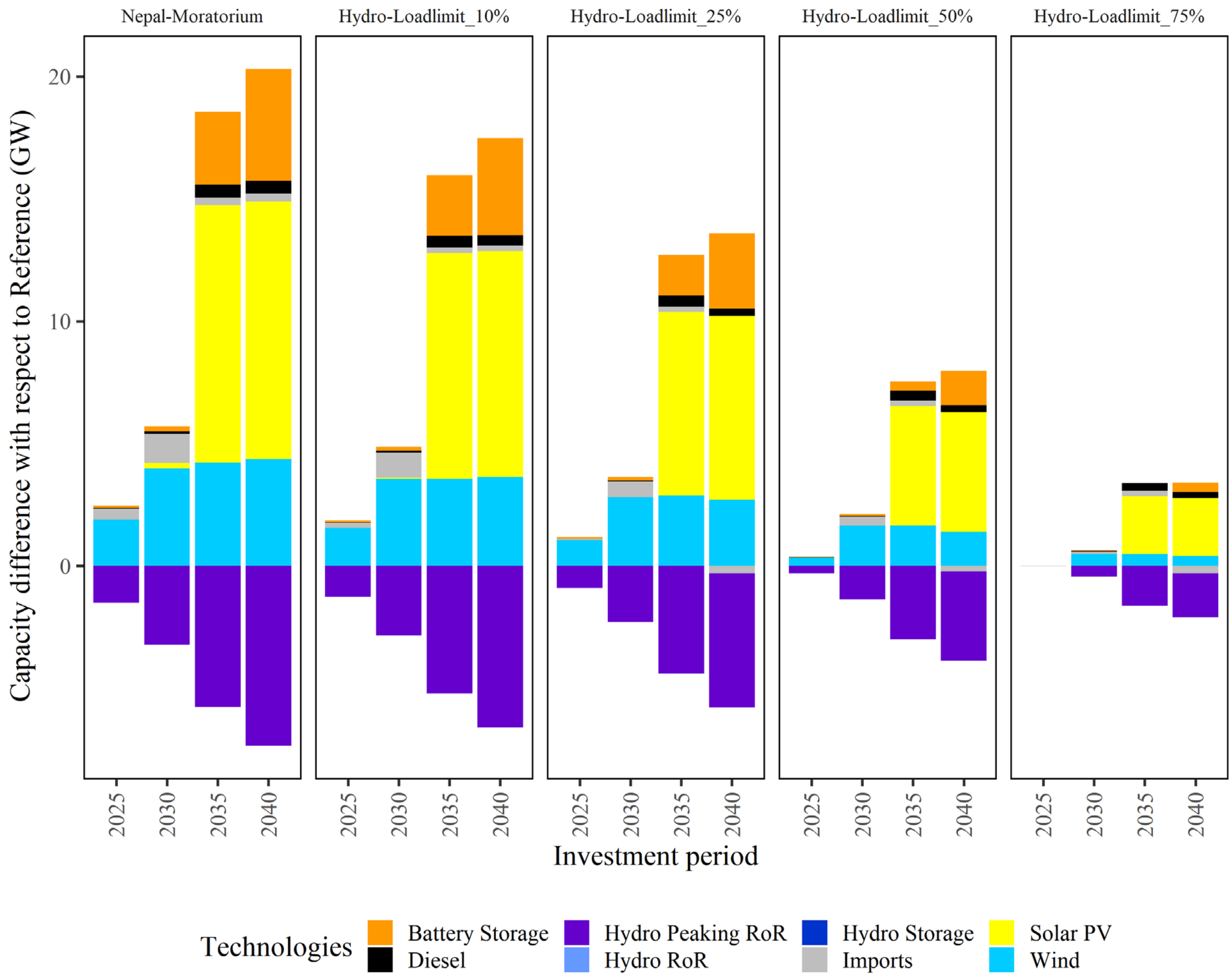

Figure A.2.3 Capacity mix differential between reference scenario and Nepal-wide hydropower limited development scenarios in SG-2

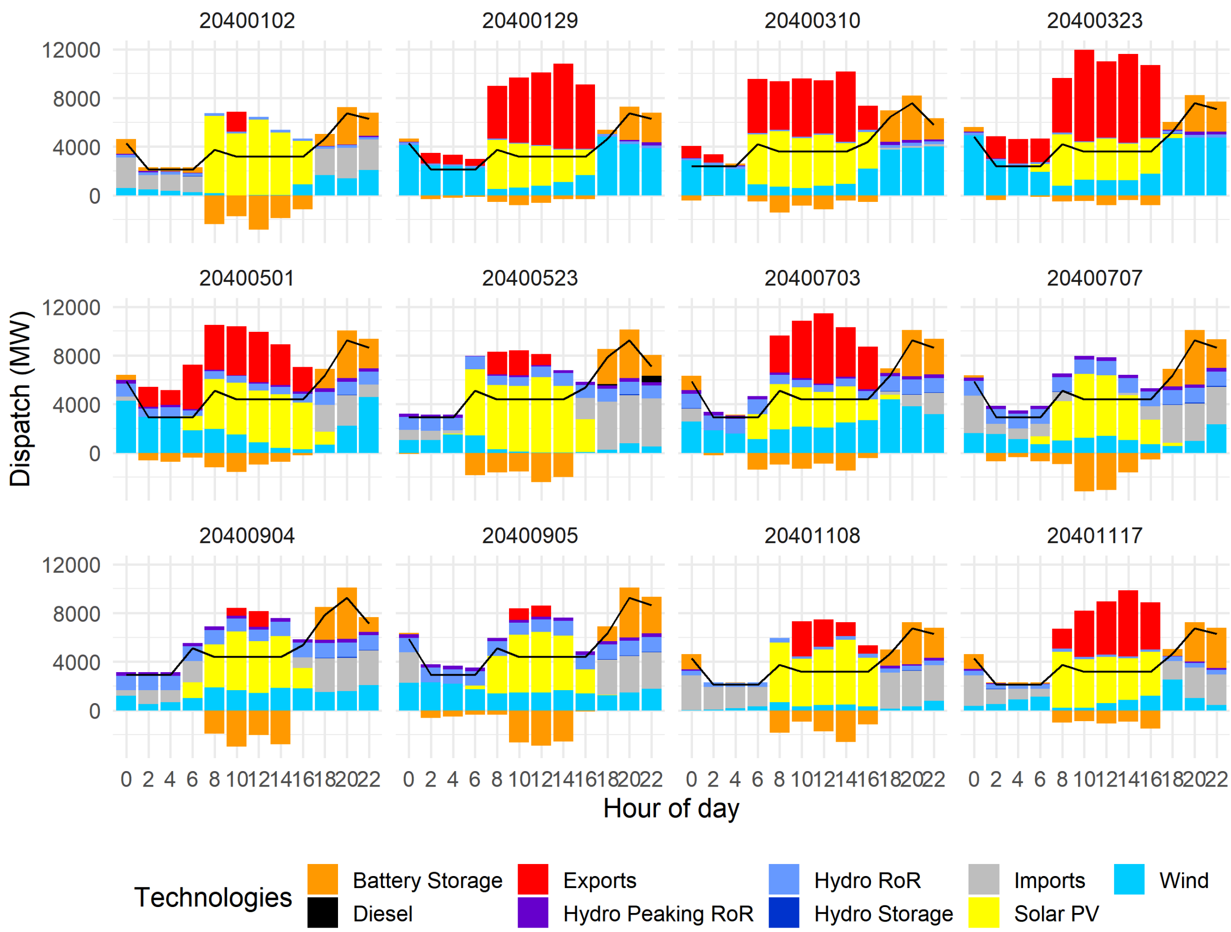

Figure A.2.4 Hourly dispatch for Nepal-Moratorium scenario in 2040

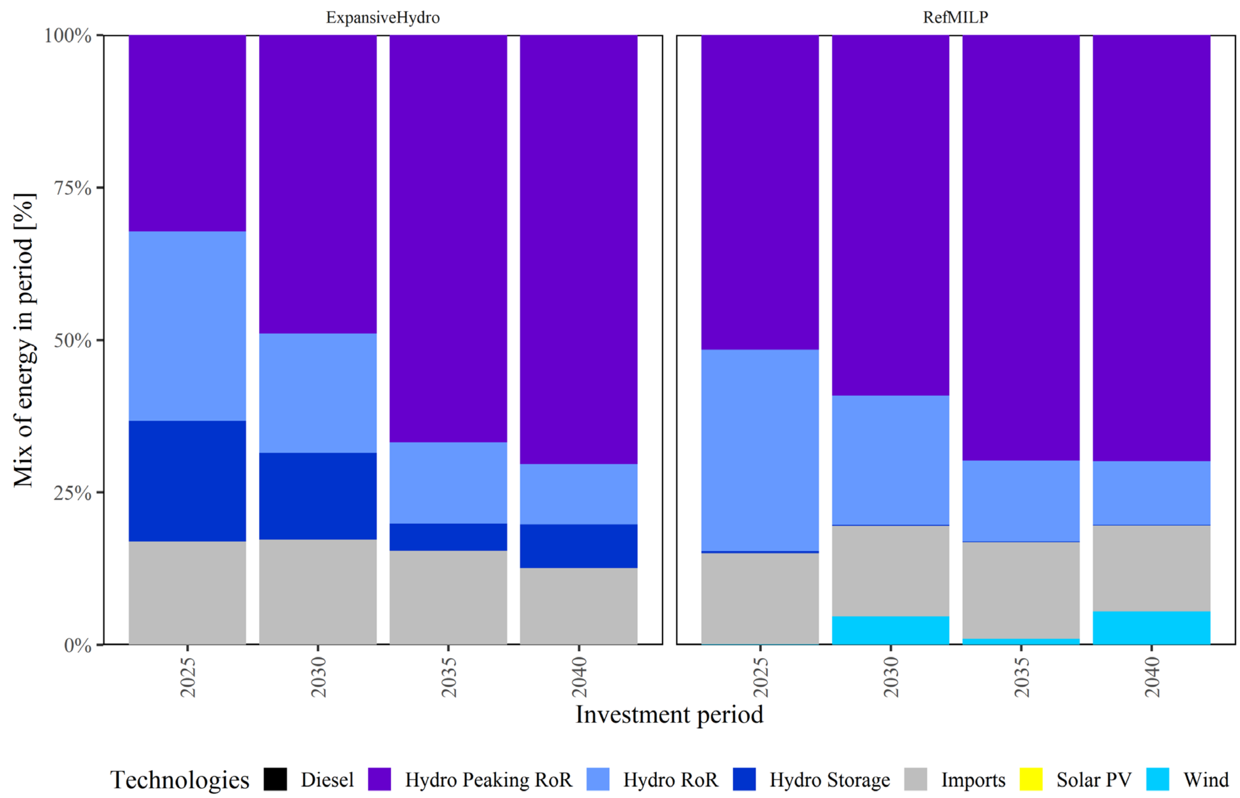

Figure A.2.5 Energy mix by period for reference (right) and expansive hydropower (left) scenarios.

6.3 Appendix C – Details of wind and solar site selection

This appendix includes information on site selection for wind and solar resources.

6.3.1 Wind

Turbine selection notes:

- w/ MERRA-2 (global), Year = 2019, 1 MW Capacity, Hub height (m) = 150, Lat = 27.46375, Lon = 82.99625
- All turbines with CF > 21.0% recorded

	Turbine	Total mean capacity factor
1	Goldwind GW140 3000	30.3 %
2	GE 1.7	29.9 %
3	Vestas V110 2000	29.0 %
4	Goldwind GW121 2500	28.8 %

5	Goldwind GW140 3400	28.2 %
6	Vestas V150 4000	28.0 %
7	Nordex N131 3000	27.7 %
8	Vestas V100 1800	26.3 %
9	Nordex N131 3000	26.2 %
10	GE 3.2 130	26.1 %
11	Vestas V100 2000	25.5 %
12	Siemens SWT 4.1 142	25.5 %
13	GE 3.4 130	25.1 %
14	Goldwind GW109 2500	24.9 %
15	Siemens Gamesa SG 4.5 145	24.9 %
16	GE 5.3 158	24.5 %
17	Siemens SWT 3.6 130	24.4 %
18	Siemens SWT 2.3 101	24.3 %
19	Goldwind G82 1500	24.2 %
20	Vestas V136 4000	24.2 %
21	GE 5.5 158	23.8 %
22	Vestas V90 1800	23.2 %
23	GE 1.6	23.2 %
24	GE 3.8 130	22.9 %
25	GE 1.5 xle	22.8 %
26	REpower MM92 2000	22.7 %
27	Siemens SWT 4.0 130	22.6 %
28	Suzlon S97 2100	22.5 %
29	Siemens SWT 3.6 120	22.4 %
30	XANT M21 100	22.4 %
31	Vestas V112 3000	22.2 %
32	Gamesa G90 2000	21.8 %

33	Enercon E82 1800	21.7 %
34	Siemens SWT 4.3 130	21.6 %
35	Vestas V90 2000	21.5 %
36	Nordex N100 2500	21.4 %
37	Alstom Eco 110	21.3 %
38	Gamesa G58 850	21.2 %
39	Nordex N27 150	21.1 %
40	Enercon E53 800	21.0 %

Sensitivity to turbine height / capacity installed on average CF for best performing turbine

- Total mean capacity factor for top 5 turbine models (at 150m)
- w/ MERRA-2 (global), Year = 2019, 1 MW Capacity, Lat = 27.46375, Lon = 82.99625

Turbine	**120 m**	**130 m**	**140 m**	**150 m**
Goldwind GW140 3000	28.4 %	29.1 %	29.7 %	30.3 %
GE 1.7	27.8 %	28.6 %	28.6 %	29.9 %
Vestas V110 2000	27.0 %	27.7 %	28.4 %	29.0 %
Goldwind GW121 2500	26.8 %	27.5 %	28.2 %	28.8 %
Goldwind GW140 3400	26.2 %	26.9 %	27.6 %	28.2 %

- Total mean capacity factor for top 5 turbine models (at 150m)
- w/ MERRA-2 (global), Year = 2019, Hub-height = 150 m, Lat = 27.46375, Lon = 82.99625

Turbine	**250 kW**	**500 kW**	**1000 kW**	**2000 kW**	**4000 kW**
Goldwind GW140 3000	30.3 %	30.3 %	30.3 %	30.3 %	30.3 %

GE 1.7	29.9 %	29.9 %	29.9 %	29.9 %	29.9 %
Vestas V110 2000	29.0 %	29.0 %	29.0 %	29.0 %	29.0 %
Goldwind GW121 2500	28.8 %	28.8 %	28.8 %	28.8 %	28.8 %
Goldwind GW140 3400	28.2 %	28.2 %	28.2 %	28.2 %	28.2 %

Best Sites

row	lon	lat	wind_pd	wind_pd_var	elev	var	On Grid?	Near Pop?	Other Notes
107348	87.12625	26.43125	186.0	1.806	69	248.7	F	Y	On Border with India near Biratnagar, SE Nepal, near future grid + interconnection with India
79558	82.97875	27.46375	192	2.700	80	1106	~	Y	Along border with India between Shivapur and Lumbini, generally within 25-30km away from existing or planned grid, mostly farmland with some village clusters
79559	82.99625	27.46375	192.2	4.494	89	387.6	~	Y	
79561	83.03125	27.46375	191.6	2.780	95	4.094	~	Y	
79560	83.01375	27.46375	191.4	2.730	93	2.418	~	Y	
79090	82.96125	27.48125	190.5	2.711	95	4.762	~	Y	
79562	83.04875	27.46375	190.0	2.869	95	3.059	~	Y	
79091	82.97875	27.48125	189.7	2.499	96	2.909	~	Y	
79563	83.06625	27.46375	189.0	3.877	95	2.577	~	Y	
78145	82.76875	27.51625	188.9	7.302	101	8.943	~	Y	
79092	82.99625	27.48125	188.7	2.906	96	3.902	~	Y	

79564	83.08375	27.46375	188.0	3.782	95	1.961	~	Y	
79093	83.01375	27.48125	187.1	2.032	95	2.150	~	Y	
79565	83.10125	27.46375	187.0	5.678	96	3.495	~	Y	
82846	83.31125	27.34125	186.2	1.544	92	4.256	~	Y	
78148	82.82125	27.51625	186.0	2.088	100	6.245	~	Y	
79095	83.04875	27.48125	185.6	3.302	96	2.782	~	Y	
82378	83.29375	27.35875	185.4	1.753	91	3.331	~	Y	
78623	82.96125	27.49875	185.3	3.808	96	2.227	~	Y	
78150	82.85625	27.51625	185.1	6.894	98	4.333	~	Y	
78151	82.87375	27.51625	185.0	6.197	100	4.390	~	Y	

Site selection notes

Sites with Wind_pd > 185, Wind_pd var < 2000, Elevation variation < 100, Elevation < 5000 m

row	*lon*	*lat*	*wind_pd*	*wind_pd_var*	*elev*	*var*	*On Grid?*	*Near Pop?*	*Other Notes*
79561	83.03125	27.46375	191.6	2.780	95	4.094	~	Y	Along border with India between Shivapur and Lumbini, generally within 25-30km away from existing or planned grid, mostly farmland with some village clusters
79560	83.01375	27.46375	191.4	2.730	93	2.418	~	Y	
79090	82.96125	27.48125	190.5	2.711	95	4.762	~	Y	
79562	83.04875	27.46375	190.0	2.869	95	3.059	~	Y	
79091	82.97875	27.48125	189.7	2.499	96	2.909	~	Y	
79563	83.06625	27.46375	189.0	3.877	95	2.577	~	Y	
78145	82.76875	27.51625	188.9	7.302	101	8.943	~	Y	

79092	82.99625	27.48125	188.7	2.906	96	3.902	~	Y	
79564	83.08375	27.46375	188.0	3.782	95	1.961	~	Y	
79094	83.03125	27.48125	187.9	4.625	96	3.219	~	Y	
79093	83.01375	27.48125	187.1	2.032	95	2.150	~	Y	
79565	83.10125	27.46375	187.0	5.678	96	3.495	~	Y	
78146	82.78625	27.51625	186.9	6.664	101	6.342	~	Y	
82846	83.31125	27.34125	186.2	1.544	92	4.256	~	Y	
78148	82.82125	27.51625	186.0	2.088	100	6.245	~	Y	
78147	82.80375	27.51625	185.9	4.301	100	6.417	~	Y	
79566	83.11875	27.46375	185.8	7.079	98	2.882	~	Y	
79095	83.04875	27.48125	185.6	3.302	96	2.782	~	Y	
82378	83.29375	27.35875	185.4	1.753	91	3.331	~	Y	
78623	82.96125	27.49875	185.3	3.808	96	2.227	~	Y	
78150	82.85625	27.51625	185.1	6.894	98	4.333	~	Y	
78151	82.87375	27.51625	185.0	6.197	100	4.390	~	Y	

Next Sites for geographic diversity with Wind_pd > 185
Wind_pd var < 2000, Elevation variation < 100, Elevation < 5000 m

row	lon	lat	wind_pd	wind_pd_var	elev	var	On Grid?	Near Pop?	Other Notes
107348	87.12625	26.43125	186.0	1.806	69	248.7	F	Y	On Border with India near Biratnagar, SE Nepal, near future grid +

									interconnection with India
79556	82.94375	27.46375	192.7	0.673	6	581.6			India
79559	82.99625	27.46375	192.2	4.494	89	387.6	~	Y	Along border with India between Shivapur and Lumbini, generally within 25-30km away from existing or planned grid, mostly farmland with some village clusters
1024	81.61375	30.40375				1012			Remote NW corner of Nepal
1025	81.63125	30.40375	227.5				N	N	Remote NW corner of Nepal
81909	83.25875	27.37625	187.8						India
78144	82.75125	27.51625	186.9						Another Shivapur / Lumbini
78622	82.94375	27.49875	186.1						Another Shivapur / Lumbini
82845	83.29375	27.34125	188.4						Another Lumbini
82377	83.27625	27.35875	188.3						Another Lumbini
558	81.63125	30.42125	274.2				N	N	Remote NW corner of Nepal
30580	83.97625	29.30125	498.1	2462	4638	831.1	N	N	Border w/ China, In Anna Purna valley
1959	81.63125	30.40375	227.5	441.5	4892	479.0	N	N	

78614	82.80375	27.49875	188						Another Shivapur / Lumbini
81910	83.27625	27.37625	185						Another Lumbini
79558	82.97875	27.46375	192	2.700	80	1106	~	Y	Another Shivapur / Lumbini, but good

78618	82.87375	27.49875	189	3.84	84	1190			Another Shivapur / Lumbini
78613	82.78625	27.49875	188	3.09	86	1180			India
81441	83.24125	27.39375	186.8			1214			India
102622	86.14625	26.60625	186.5			1119			India, near Janakpur, Nepal
81442	83.25875	27.39375	185.7			1199			Another Shivapur / Lumbini
1959	81.63125	30.36875	240	979			N	N	Remote NW corner of Nepal
82844	83.27625	27.34125	190			1441			India
78619	82.89125	27.49875	187			1355			India
80034	83.13625	27.44625	185			1502			India
32915	83.97625	29.21375	312	1223		1526			Border w/ China, In Anna Purna valley, on a glacier
1027	81.66625	30.40375	290	1282		1267	N	N	Remote NW corner of Nepal
78617	82.85625	27.49875	189			1622			India

6.3.2 Solar

Best Sites

row	lon	lat	elev	var	solar	On Grid?	Other Notes
263117	84.01833	28.21000	834	26.636	4.314	Y	E Pokhara outskirts, Farmland
266061	84.05167	28.18500	752	17.828	4.271	Y	SE Pokhara, E outskirts, somewhat farmland
321104	85.41000	27.71833	1328	21.971	4.269	Y	NE Kathmandu, Farmland
266057	84.01833	28.18500	791	27.047	4.258	Y	SE Pokhara, on Pokhara Intl Airport land

322083	85.40167	27.71000	1322	16.009	4.249	Y	E Kathmandu outskirt, Mulpali, Farmland around Manohara River, partial cell
324048	85.44333	27.69333	1333	38.106	4.246	Y	E Kathmandu outskirt, Baktapur, greenspace
216766	81.59333	28.60167	674	32.460	4.227	F	NE Surkhet, on proposed 132 kV node, farmlan/sparse suburbs
269004	84.07667	28.16000	692	14.586	4.219	Y	SE Pokhara outskirt, suburban but space
217746	81.59333	28.59333	660	27.421	4.210	F	Surkhet, on proposed 132 kV node, farmland
217745	81.58500	28.59333	656	22.212	4.205	F	Surkhet, on proposed 132 kV node, farmland
271724	82.24333	28.13500	650	21.997	4.202	F	Tulsipur outskirts, farmland
274668	82.27667	28.11000	623	12.027	4.201	F	Tulsipur (on proposed 400 kV/132 KV intersection at future substation), farmland
274669	82.28500	28.11000	629	20.593	4.201	F	Tulsipur (on proposed 400 kV/132 KV intersection at future substation), farmland
272704	82.24333	28.12667	635	20.381	4.200	F	N Tulsipur, farmland
269985	84.08500	28.15167	675	16.209	4.200	Y	NE Pokhara, farmland
218727	81.60167	28.58500	654	16.045	4.198	F	W Surkhet, semi farmland + suburban
274666	82.26000	28.11000	603	21.925	4.196	F	NW Tulsipur, farmland S of Patu Khola floodplain
275648	82.27667	28.10167	613	11.699	4.195	F	N Tulsipur, farmland
272703	82.23500	28.12667	627	19.488	4.195	F	NW Tulsipur, farmland
218726	81.59333	28.58500	649	10.427	4.194	F	W Surkhet, farmland
107064	82.07667	29.53500	2975	370	4.933	F	1 cell at Nepal Army Rara or Rara Heliport, large variance but facing south, if at edge of lake ok
230661	83.05167	28.48500	2862	5.325	4.263	F	Dhorpatan Valley, at site of Pelma (90) hydropower license, on proposed 132 kV
230660	83.04333	28.48500	2857	4.079	4.220	F	Dhorpatan Valley, at site of Pelma (90) hydropower license, on proposed 132 kV

132772	83.97667	29.31833	4598	11.867	5.442	N	5 cells in Annapurna Conservation area, border w/ China, part of cluster in Kora La
275647	82.26833	28.10167	610	10.515	4.193	F	N Tulsipur, farmland
273683	82.23500	28.11833	614	24.515	4.192	F	NW Tulsipur, farmland
290355	82.33500	27.97667	625	25.401	4.191	F	Between Phulbari + Ghorahi, on proposed 400 KV line
275646	82.26000	28.10167	610	18.755	4.191	F	NW Tulsipur, farmland
273695	82.33500	28.11833	636	21.636	4.190	F	E Tulsipur, farmland S of Gwar Khola flood plain
273694	82.32667	28.11833	630	28.628	4.193	F	NE Tulsipur, farmland N of Gwar Khola flood plain

Site selection notes

Sites with Solar > 5, Elevation variation < 40, Elevation < 5000 m

row	lon	lat	elev	var	solar	Near Pop?	Near Grid?	Other Notes
~~105182~~	~~82.72667~~	~~29.55167~~	~~4295~~	~~2.131~~	~~5.018~~	~~n~~	~~N~~	~~Remote in Shey-Phoksundo NP~~
132771	83.96833	29.31833	4599	10.534	5.347	n	N	In Annapurna Conservation area, border w/ China, part of cluster in Kora La
132772	83.97667	29.31833	4598	11.867	5.442	n	N	
132773	83.98500	29.31833	4601	24.545	5.524	n	N	
133752	83.97667	29.31000	4605	20.947	5.469	n	N	
131791	83.96833	29.32667	4604	36.087	5.356	n	N	
133753	83.98500	29.31000	4618	36.786	5.544	n	N	

Sites with Solar 5 > x > 4.75, Elevation variation < 40, Elevation < 5000 m

row	lon	lat	elev	var	solar	Near Pop?	Near Grid?	Other Notes
108046	82.09333	29.52667	2970	0.000	4.809		N	

108045	82.08500	29.52667	2970	0.000	4.828		N	Middle of a lake in Rara national park
107068	82.11000	29.53500	2970	0.000	4.844		N	
108044	82.07667	29.52667	2970	0.000	4.851		N	
107067	82.10167	29.53500	2970	0.000	4.868		N	
107066	82.09333	29.53500	2970	0.000	4.894		N	
107065	82.08500	29.53500	2970	0.000	4.915		N	

- Maybe 1 cell available at Nepal Army Rara or Rara Heliport [29.5400 , 82.08050]
    - Variance there is large - 4589.37, but the slope is south facing with nearby loads?
    - 82.073968, 29.538792, e = 2975, e_var = 370, solar = 4.933
    - 82.083384, 29.541761, 3039.77, 4589.371, 5.004
    - 82.078949, 29.540575, 3121.47, 5902.171, 5.029,
    - 82.071614, 29.537579, 3047.69 4020.115 4.932
- Or 1-2 cells on south part of lake (part of tourist attraction though)
- Rara NP near proposed 400 kV line

Sites with Solar 4.75 > x > 4.3, Elevation variation < 40, Elevation < 5000 m

row	lon	lat	elev	var	solar	Near Pop?	Near Grid?	Other Notes
263117	84.01833	28.21000	834	26.636	4.314	Y	Y	E outskirts of Pokhara
51191	81.96833	30.01000	4200	36.353	4.501	n	n	Remote mountain
106163	82.73500	29.54333	4303	9.173	4.463	n	n	Remote in Shey-Phoksundo NP
106164	82.74333	29.54333	4309	4.421	4.705	n	n	
105183	82.73500	29.55167	4294	16.535	4.737	n	n	

Site in Pokhara looks promising, nearby field at [28.211091, 84.023649] has open area too. Variance higher (1147.929), solar basically the same (4.284). Sites with Solar 4.3 > x > 4.25, Elevation variation < 40, Elevation < 5000 m

row	lon	lat	elev	var	solar	Near Pop?	Near Grid?	Other Notes
265075	84.00167	28.19333	816	25.616	4.250	Y	Y	SE Pokhara, NW of Pokhara Intl Airport, somewhat suburbs
264094	83.99333	28.20167	834	22.578	4.255	Y	Y	Urban Pohkara
~~106161~~	~~82.71833~~	~~29.54333~~	~~4294~~	~~38.583~~	~~4.258~~	~~n~~	~~n~~	~~Remote in Shey-Phoksundo NP~~
266057	84.01833	28.18500	791	27.047	4.258	Y	Y	SE Pokhara, Pokhara Intl Airport land
230661	83.05167	28.48500	2862	5.325	4.263	~	~F	Dhorpatan Valley, at site of Pelma (90) hydropower license, on proposed 132 kV
~~106162~~	~~82.72667~~	~~29.54333~~	~~4300~~	~~15.079~~	~~4.264~~	~~N~~	~~N~~	~~Remote in Shey-Phoksundo NP~~
265076	84.01000	28.19333	813	29.181	4.268	Y	Y	SE Pokhara, N of Pokhara Intl Airport, somewhat urban
321104	85.41000	27.71833	1328	21.971	4.269	Y	Y	Farmland NE of Kathmandu
264095	84.00167	28.20167	834	28.686	4.271	Y	Y	Urban Pokhara
266061	84.05167	28.18500	752	17.828	4.271	Y	Y	SE Pokhara, E outskirts, somewhat farmland
265077	84.01833	28.19333	806	27.375	4.279	Y	Y	SE Pokhara, NE of Pokhara Intl Airport, somewhat suburbs
264096	84.01000	28.20167	830	27.738	4.286	Y	Y	E Pokhara, N of Pokhara Intl Airport, somewhat urban
263115	84.00167	28.21000	851	33.684	4.291	Y	Y	E Pokhara, urban
264097	84.01833	28.20167	820	31.843	4.295			E Pokhara, N of Pokhara Intl Airport, somewhat suburbs

Sites with Solar 4.25 > x > 4.2, Elevation variation < 40, Elevation < 5000 m

row	*lon*	*lat*	*elev*	*var*	*solar*	*Near Pop?*	*Near Grid?*	*Other Notes*

218730	81.62667	28.58500	672	37.206	4.201	Y	F	In Surkhet, Birendranagar, on proposed 132 kV node, suburban
273688	82.27667	28.11833	629	22.130	4.201		F	On river floodplain near Dang Airport, In Tulsipur, on proposed 400 kV/132 KV intersection at future substation
274668	82.27667	28.11000	623	12.027	4.201	Y	F	In Tulsipur (on proposed 400 kV/132 KV intersection at future substation), farmland
274669	82.28500	28.11000	629	20.593	4.201	Y	F	In Tulsipur (on proposed 400 kV/132 KV intersection at future substation), farmland
218729	81.61833	28.58500	661	29.136	4.202	Y	F	In Surkhet, Birendranagar, on proposed 132 kV node, some open space but suburban
271724	82.24333	28.13500	650	21.997	4.202	Y	F	Outskirts of Tulsipur, farmland
273690	82.29333	28.11833	645	26.127	4.202	Y	F	In Tulsipur, near Dang Airport, suburban
273689	82.28500	28.11833	639	13.297	4.204	Y	F	Next to river floodplain near Dang Airport, In Tulsipur, on proposed 400 kV/132 KV intersection at future substation
217745	81.58500	28.59333	656	22.212	4.205	Y	F	Surkhet, on proposed 132 kV node, farmland

217746	81.59333	28.59333	660	27.421	4.210	Y	F	Surkhet, on proposed 132 kV node, farmland
320115	85.33500	27.72667	1324	31.319	4.211	Y	Y	Urban Kathmandu
~~43233~~	~~80.98500~~	~~30.07667~~	~~4169~~	~~17.983~~	~~4.214~~	~~N~~	~~N~~	~~Remote mountain in NW nepal~~
217747	81.60167	28.59333	668	32.300	4.214	Y	F	Surkhet, on proposed 132 kV node, suburban
264092	83.97667	28.20167	822	31.795	4.214	Y	Y	Urban Pokhara
~~43232~~	~~80.97667~~	~~30.07667~~	~~4181~~	~~35.583~~	~~4.215~~	~~N~~	~~N~~	~~Remote mountain in NW nepal~~
217748	81.61000	28.59333	674	29.541	4.217	Y	F	Urban Surkhet
269004	84.07667	28.16000	692	14.586	4.219	Y	Y	SE Pokhara outskirt, suburban but space
230660	83.04333	28.48500	2857	4.079	4.220	~	~F	Dhorpatan Valley, at site of Pelma (90) hydropower license, on proposed 132 kV
319135	85.33500	27.73500	1339	39.290	4.226			Urban Kathmandu
216766	81.59333	28.60167	674	32.460	4.227	Y	F	NE Surkhet, on proposed 132 kV node, farmlan/sparse suburbs
266055	84.00167	28.18500	799	28.787	4.229	Y	Y	S Pokhara suburbs, south of intl airport
265074	83.99333	28.19333	817	26.074	4.232	Y	Y	S Pokhara suburbs, W of intl airport
321100	85.37667	27.71833	1320	33.553	4.232	Y	Y	Urban Kathmandu
263112	83.97667	28.21000	838	35.646	4.237	Y	Y	Urban Pokhara
266056	84.01000	28.18500	797	22.163	4.246	Y	Y	Pokhara Intl Airport Land (already 1 cell designated

267037	84.01833	28.17667	776	31.845	4.246	Y	Y	Suburban S Pokhara
324048	85.44333	27.69333	1333	38.106	4.246	Y	Y	E Kathmandu outskirt, Baktapur, greenspace
322083	85.40167	27.71000	1322	16.009	4.249	Y	Y	E Kathmandu outskirt, Mulpali, Farmland around Manohara River, partial cell

Sites with Solar 4.2 > x > 4.19, Elevation variation < 30, Elevation < 5000 m

row	*lon*	*lat*	*elev*	*var*	*solar*	*Near Pop?*	*Near Grid?*	*Other Notes*
273695	82.33500	28.11833	636	21.636	4.190	Y	F	E Tulsipur, farmland S of Gwar Khola flood plain
274673	82.31833	28.11000	619	8.235	4.190	Y	F	E Tulsipur, Gwar Khola flood plain
324039	85.36833	27.69333	1310	25.805	4.190	Y	Y	Urban Kathmandu
275646	82.26000	28.10167	610	18.755	4.191	Y	F	NW Tulsipur, farmland
290355	82.33500	27.97667	625	25.401	4.191	~	F	Between Phulbari + Ghorahi, on proposed 400 KV line
273683	82.23500	28.11833	614	24.515	4.192	Y	F	NW Tulsipur, farmland
274672	82.31000	28.11000	613	17.738	4.192	Y	F	E Tulsipur, Gwar Khola flood plain
273694	82.32667	28.11833	630	28.628	4.193	Y	F	NE Tulsipur, farmland N of Gwar Khola flood plain
275647	82.26833	28.10167	610	10.515	4.193	Y	F	N Tulsipur, farmland
218726	81.59333	28.58500	649	10.427	4.194	Y	F	W Surkhet, farmland

319132	85.31000	27.73500	1305	6.432	4.194	Y	Y	Urban Kathmandu
272703	82.23500	28.12667	627	19.488	4.195	Y	F	NW Tulsipur, farmland
274665	82.25167	28.11000	597	23.799	4.195	Y	F	Tulsipur, Patu Khola floodplain
275648	82.27667	28.10167	613	11.699	4.195	Y	F	N Tulsipur, farmland
275649	82.28500	28.10167	618	15.145	4.195	Y	F	N Tulsipur, farmland + suburbs, but land better right beside (275648)
274666	82.26000	28.11000	603	21.925	4.196	Y	F	NW Tulsipur, farmland S of Patu Khola floodplain
326003	85.40167	27.67667	1307	5.381	4.197	Y	Y	Urban SE Kathmandu
218727	81.60167	28.58500	654	16.045	4.198	Y	F	W Surkhet, semi farmland + suburban
218731	81.63500	28.58500	677	22.615	4.198	Y	F	Surkhet airport
273684	82.24333	28.11833	621	19.541	4.198	Y	F	NW Tulsipur, farmland + suburbs, but land better right north
274667	82.26833	28.11000	616	22.577	4.198	Y	F	N Tulsipur, farmland + suburbs, but land better right beside
274670	82.29333	28.11000	630	17.005	4.198	Y	F	Tulsipur, Dang Airport, land better just to the east
218728	81.61000	28.58500	658	16.744	4.200	Y	F	Surkhet, suburbs
269985	84.08500	28.15167	675	16.209	4.200	Y	Y	NE Pokhara, farmland
272704	82.24333	28.12667	635	20.381	4.200	Y	F	N Tulsipur, farmland